EnCana Corporation
Annual Report
2004

# UNCONVENTIONAL

EnCana™

energy for people

**Strategic Focus**

- North American Natural Gas
- Canadian In-Situ Oilsands

**Leading Natural Gas Producer**

**85%**

*of operating cash flow from natural gas and natural gas liquids*

**Strategic Assets**

High-Quality, Long-Life Resource Plays

# Unconventional EnCana Corporation

## Why Invest in EnCana?

EnCana is North America's leading natural gas producer. Its growing production is supported by extensive proved reserves and significant unbooked resource potential. The company is focused on the development of huge unconventional reservoirs where large-scale repeatable drilling programs can deliver predictable and profitable production growth. EnCana's portfolio of long-life resource plays includes 10 key plays in Canada and the United States, eight producing natural gas and two focused on oil. The company's primary goal is to continue to increase net asset value per share by balancing capital investment between the disciplined development of its large inventory of resource plays and the return of capital to shareholders through share buybacks.

## Decisions Focused on Building Net Asset Value Per Share

| NATURAL GAS RESERVES GROWTH PER SHARE | NATURAL GAS SALES GROWTH PER SHARE | NATURAL GAS PRODUCTION REPLACEMENT |
|---|---|---|
| 28% | 21% | 286% |
| to 22.7 Mcf/share | to 2.4 Mcf/share | proved reserve life index of 9.5 years |

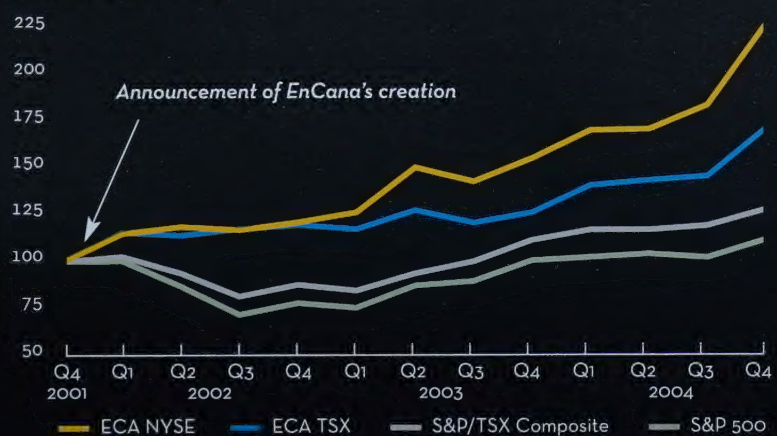
## RESOURCE PLAYS DRIVE GROWTH IN SHAREHOLDER VALUE

## FINANCIAL HIGHLIGHTS

| *US$ millions, except per share amounts* | 2004 | 2003 | % Change |
|---|---|---|---|
| Revenues, net of royalties* | 12,433 | 10,303 | 21 |
| Cash Flow | 4,980 | 4,459 | 12 |
| Per Share – diluted | 10.64 | 9.30 | 14 |
| Net Earnings | 3,513 | 2,360 | 49 |
| Per Share – diluted | 7.51 | 4.92 | 53 |
| Operating Earnings** | 1,976 | 1,399 | 41 |
| Per Share – diluted | 4.22 | 2.92 | 45 |
| Net Capital Investment | 4,206 | 3,422 | |
| Share Buyback *(millions of shares)* | 20.0 | 23.8 | |
| Debt-to-Capitalization (%) | 33 | 33 | |
| Debt-to-EBITDA *(times)* | 1.4 | 1.3 | |
| Return on Capital Employed (%) | 20 | 17 | |
| Return on Common Equity (%) | 27 | 24 | |

* *Including discontinued operations.*
** *Operating earnings as defined on page 55.*

### ENCANA TOTAL RETURN VS. MAJOR INDICES
**(December 31, 2001 = 100)**




## OPERATING HIGHLIGHTS

| *After Royalties* | 2004 | 2003 | % Change |
|---|---|---|---|
| **Continuing Operations** | | | |
| North America | | | |
| Natural Gas Sales *(MMcf/d)* | | | |
| Canada | 2,099 | 1,965 | 7 |
| U.S.A. | 869 | 588 | 48 |
| | 2,968 | 2,553 | 16 |
| Oil and NGLs Sales *(bbls/d)* | 166,417 | 165,895 | – |
| Total Sales Continuing Operations *(MMcfe/d)* | 3,966 | 3,548 | 12 |
| **Discontinued Operations** | | | |
| U.K. Natural Gas Sales *(MMcf/d)* | 30 | 13 | 131 |
| U.K. Oil and NGLs Sales *(bbls/d)* | 15,973 | 10,128 | 58 |
| Ecuador Oil Sales *(bbls/d)* | 77,993 | 46,521 | 68 |
| Syncrude Oil Sales *(bbls/d)* | – | 7,629 | – |
| Total Sales *(MMcfe/d)* | 4,560 | 3,947 | 16 |
| Total Sales *(BOE/d)* | 760,050 | 657,840 | 16 |
| Net Reserves Additions *(Bcfe)** | 3,163 | 2,892 | |
| Production Replacement *(%)** | 189 | 203 | |
| Reserve Replacement Cost *($/Mcfe)** | 1.40 | 1.50 | |
| Finding & Development Cost *($/Mcfe)** | 1.44 | 1.43 | |
| Reserve Life Index *(years)** | 9.3 | 10.0 | |
| Year-end Reserves *(Bcfe)** | 15,643 | 14,154 | |

* *Before bitumen revision as discussed on page 64.*

## ADVISORY

Certain information regarding the Company and its subsidiaries set forth in this document, including management's assessment of the Company's future plans and operations, may constitute "forward-looking statements" under applicable securities laws and necessarily involve risks and uncertainties associated with future events. As a consequence, actual results may differ materially from those anticipated in the forward-looking statements. See page 47 for a more detailed advisory.

For convenience, references in this Annual Report to "EnCana", the "Company", the "company", "we", "us", "our" and similar references may, where applicable, refer only to or include any relevant direct and indirect subsidiary corporations and partnerships (each a "Subsidiary" or if more than one, "Subsidiaries") and the assets, activities and initiatives thereof. References to financial results of operations refer to the consolidated financial results of EnCana Corporation and its Subsidiaries, taken as a whole, except where otherwise noted or the context otherwise implies.

This Annual Report contains references to measures commonly referred to as non-GAAP measures. Additional disclosure relating to these measures is set forth in Management's Discussion and Analysis on pages 54, 55 and 56 and the advisory found on page 48 of this Annual Report.

ENCANA™

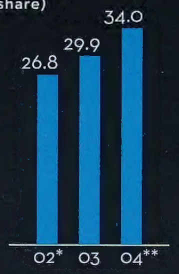
*energy for people*

SALES PER SHARE (Mcfe/share)


### STRONG SALES GROWTH

*EnCana achieved per share sales growth of 19% in 2004.*

RESERVES PER SHARE (Mcfe/share)




### CONSISTENT RESERVES GROWTH

*(2002 reserve number excludes Syncrude reserves)*

*Reserves grew by 14% per share, a clear demonstration of the growth potential of the company's North American asset base.*

CASH FLOW PER SHARE ($/share)


### RECORD CASH FLOW

*Per share cash flow rose 14% in 2004. Growth in sales volumes together with strong commodity prices generated cash flow of $4.98 billion.*

* *2002 financial and operating information is presented on an unaudited, pro forma basis as if the merger of PanCanadian Energy Corporation and Alberta Energy Company Ltd. had occurred at the beginning of 2002.*

** *Before bitumen revision.*

TARGETING

**100%**

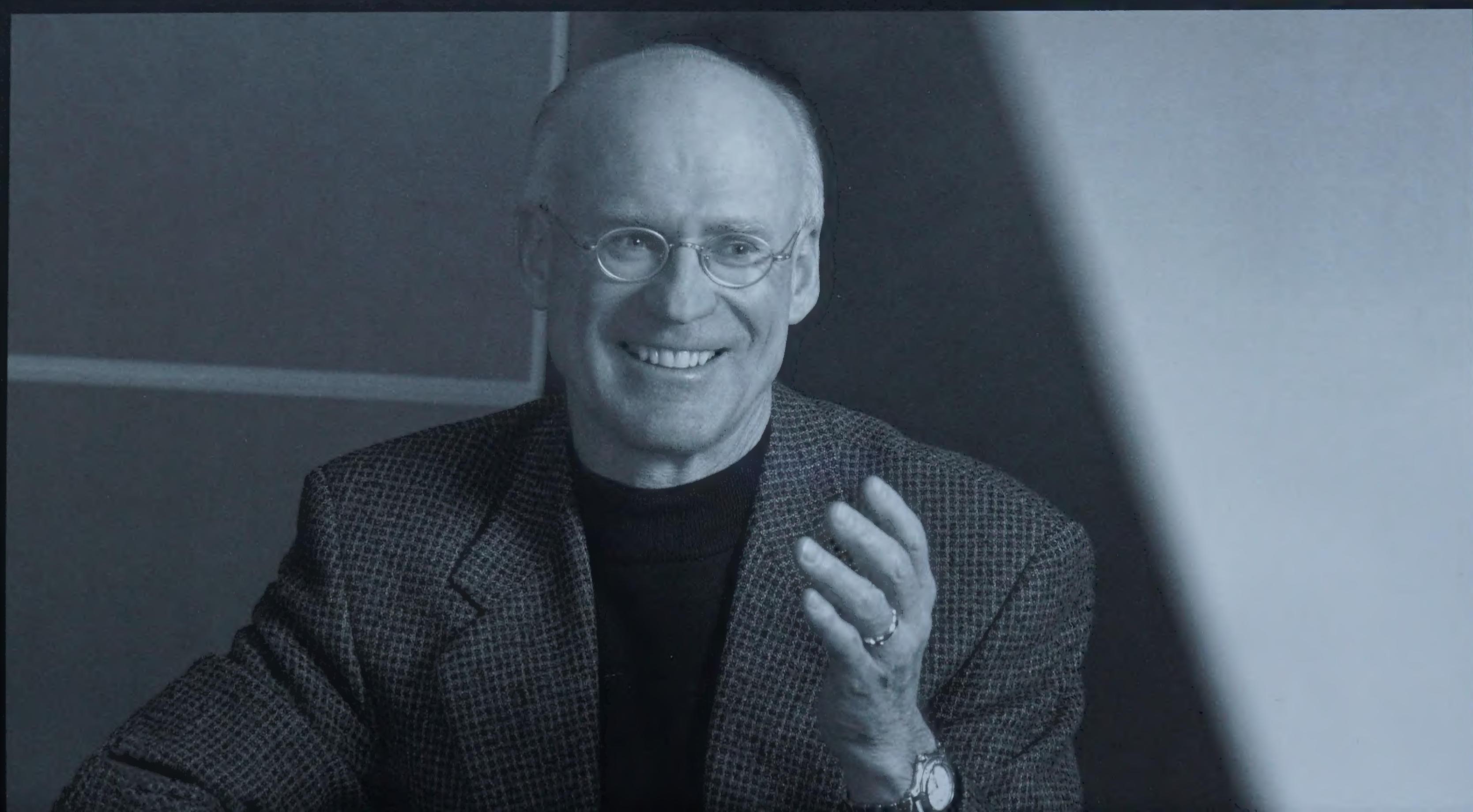
North American production after planned divestitures

**10%**

Annual per share sales growth for at least five years

**18 million**

Net undeveloped acres onshore North America




**To fellow shareholders from EnCana's President & Chief Executive Officer Gwyn Morgan**

# UNCONVENTIONAL THINKING

**YOUR UNCONVENTIONAL RESOURCE COMPANY** We are a company built upon unconventional thinking. Most notably, our asset base is focused on unconventional gas and oil reservoirs, containing resources capable of sustainable growth right here in North America.

**FOCUSING ON OUR COMPETITIVE ADVANTAGES** EnCana's third year of operation was defined by the sharpening of the company's focus to where we have clear and sustainable competitive advantage: North American natural gas and in-situ oilsands.

**LEADING IN NATURAL GAS** We are currently North America's leading producer of natural gas and our land holdings contain huge undeveloped resources. Our large-scale natural gas drilling programs efficiently drive strong internal production growth.

ADVANTAGE

During our first three years of operation, EnCana's average annual growth in gas sales has been 13 percent and our 2005 growth is expected to be in the range of 15 percent. Looking forward, we are confident that our existing land base and financial capacity are capable of sustaining internal 10 percent per share sales growth annually for at least five years to come.

**IN-SITU OILSANDS TECHNOLOGY LEADER** The term in-situ means that the thick bitumen from subsurface oilsands is mobilized through injecting steam into specialized wells. The importance of in-situ oilsands production methods is placed into perspective by the fact that less than 10 percent of Canada's oilsands resources are considered accessible by surface mining methods. EnCana's teams have achieved technical and cost leadership in the production of bitumen from in-situ oilsands and our extensive land holdings are recognized for their high quality and potential. We have compiled the longest and most successful track record in the application of the latest generation recovery process known as steam-assisted gravity drainage (SAGD).

**RESOURCE PLAYS – THE FUTURE OF NORTH AMERICAN PRODUCTION** It has become clear that conventional North American gas and oil production has entered the classic resource cycle phase of decreasing discovery size and frequency. In other words, conventional resources are in their later stages of the exploration cycle. This does not mean that North America is running out of gas and oil. There are huge gas resources contained in unconventional tight sand, carbonate and coal reservoirs which, together with oilsands, will dominate future North American production. The term increasingly used to describe these reservoirs is resource plays. This raises the question: If this is now widely recognized, why does EnCana feel it can maintain its current competitive advantages? Before answering the question I should acknowledge that we do have competition in pursuing resource plays, and we will have more. But there are barriers to entry.

**COMPETITIVE ADVANTAGES – UNCONVENTIONAL THINKING** EnCana's technical and operating teams have grown up in a company principally focused on resource plays, whereas the main focus of the vast majority of the industry has been on the search for new conventional fields. Successful pursuit of resource plays requires a very different mindset, one trained on assessing the size of previously unproducible resources, finding the technical key to unlocking that potential and acting decisively to acquire very large land blocks containing the play. Then, it requires driving down costs and driving up reserves and production through continually improving technical and operational understanding and thinking creatively over decades of resource play life.

**COMPETITIVE ADVANTAGES – UNPARALLELED LAND POSITION** Over a 30-year history, EnCana and its two predecessor companies have assembled approximately 18 million net undeveloped acres onshore North America which contain some of the continent's highest quality unconventional natural gas resources, a position that could not be replicated today.

**REFINING OUR STRATEGIC FOCUS** Focusing where you have competitive advantage means strengthening your asset position where you have clear advantage, and exiting asset positions where you don't.

In 2004, EnCana took decisive action to do both. We added to our North American natural gas position with the $2.7 billion acquisition of Denver-based Tom Brown, Inc., a hand-in-glove fit with EnCana USA's growing resource play assets in the Rocky Mountain states and Texas.

On the divestiture side, we sold later-life, higher-cost Canadian conventional assets yielding attractive valuations totalling $1.4 billion. And the December sale of EnCana's entire U.K. North Sea position for $2.1 billion yielded a large earnings gain.

Overall, resource play acquisitions totalled $3.1 billion, while divestitures of conventional and other non-core assets totalled $3.7 billion.

During 2005, we are planning the divestiture of our assets in Ecuador and the Gulf of Mexico, as well as additional Canadian conventional production. Completion of these divestitures would move EnCana's production to 100 percent North American, about 80 percent of which would be natural gas, creating the bellwether North American natural gas investment.

*Completion of planned divestitures would move EnCana's production to about 80 percent natural gas, creating the bellwether North American natural gas investment.*

**DISCIPLINED CREATION OF NET ASSET VALUE PER SHARE** Our $4.9 billion 2004 total upstream core capital expenditures were funded by cash flow, and we expect our 2005 core capital will be as well. We have announced that use of proceeds from our divestiture programs will be balanced between debt reduction and return of capital to investors through share buyback. In 2004, $1.0 billion was invested in purchasing 4.3 percent of EnCana's shares. In 2005, the successful divestiture of additional non-core assets affords us the opportunity to purchase up to 10 percent of our public float which is authorized under our current Normal Course Issuer Bid. Longer term, we believe that a combination of asset value creation through continuing production and reserve growth, combined with deployment of surplus cash to further reduce shares outstanding, will yield attractive net asset value (NAV) per share growth for shareholders.

FOCUS

**NATURAL GAS RESOURCE PLAYS DRIVE OUTSTANDING SALES AND RESERVES GROWTH** For the third consecutive year since EnCana began operations, our North American gas resource plays drove substantial value creation. In 2004, natural gas and natural gas liquids provided 85 percent of EnCana's operating cash flow. Total gas sales increased 17 percent to

3 billion cubic feet per day. Operating and administrative costs of $0.70 per thousand cubic feet equivalent are again expected to be among the lowest in our peer group.

Proved North American gas reserves now stand at 10.5 trillion cubic feet. Independent qualified reserve evaluators reported proved gas reserve additions of 3.1 trillion cubic feet, 71 percent of which was organic. Excluding acquisitions and divestitures, EnCana's organic gas production replacement was 204 percent. The combination of drilling, acquisitions and divestitures generated a reserve replacement cost for gas and liquids of $1.40 per thousand cubic feet equivalent as shown in the operating highlights on page 2. This compares with an average netback for all products, after operating and administrative costs, of $4.00 per thousand cubic feet equivalent, generating a recycle ratio of 2.9 times. These metrics are important as they demonstrate the ability of our resource plays to generate profitable production and reserve growth.

Big numbers, and if our foundation was built on conventional assets, this shareholder letter would now move to the next topic, but since EnCana is unconventional there are more resources to tell you about.

**RESOURCE PLAYS HOLD HUGE POTENTIAL** Unlike conventional reservoirs, EnCana's resource plays contain a huge inventory of unbooked potential. EnCana's teams have a lengthy and reliable track record of translating resources to proved reserves through low-risk, large-scale exploitation drilling. And, even as we're converting these unbooked resources to proved reserves, more unbooked resource potential is being added, so that both our proved reserves and our unbooked resource potential have continuously grown. In this way, we keep building the company's resource base.

We estimate that 16 trillion cubic feet of natural gas can be converted to proved reserves over the next five years, an amount that is 1.5 times our year-end proved reserve base. Together, our proved reserves and five-year unbooked resource potential are 26.5 trillion cubic feet, which represents about 24 years of resource life at 2004 production rates.

This is the key to EnCana's unique ability to continually grow reserves and production through a low-risk, strong return capital investment program.

One of our oldest resource plays shows how this is accomplished. The Suffield shallow gas field, an unconventional tight gas reservoir, has been on production for almost 30 years and yet it continues to show solid results. Today it is producing more than a quarter of a billion cubic feet of gas per day, even after cumulative production has surpassed the original estimate of its ultimate reserve recovery. Over the years, generations of technical and operating teams have continuously increased their understanding of the reservoir and creatively applied improved technology to drive down costs and increase production. Our teams have continually improved technical and operating procedures so that essentially all capital inflation has been offset. In other words, well costs today are about the same as 30 years ago. Suffield's average well decline rate of less than 15 percent is also a graphic illustration of another unique resource play attribute – well decline rates that flatten out over long producing lives.

POTENTIAL

This unconventional characteristic of production and reserve increases over long periods combined with reducing costs and decline rates illustrates EnCana's resource play advantage. Further, when one considers that most of our gas resource plays – including those in British Columbia, the U.S. Rocky Mountain states and Texas – are at a much

earlier stage in their life cycle, you can see why we have so much confidence in the long-term future of our company.

**ENCANA'S OIL ASSETS – A YEAR OF TRANSITION** Total liquids production grew 13 percent to 260,000 barrels per day, even though conventional oil asset divestitures totalling 20,800 barrels per day occurred at various points in the year.

EXECUTION

Booked liquids reserves were also impacted by the U.S. Securities and Exchange Commission (SEC) requirement of using an unusually large year-end gravity price differential in calculating the bitumen reserves for our in-situ oilsands operations, resulting in their removal from the proved category. Overall for the year, much higher returns were achieved and expansion plans of our bitumen production for 2005 and 2006 were announced.

**QUALITY ASSETS DRIVE STRONG RETURNS** EnCana's management has a long track record of favouring wholly owned assets containing large resources with growth potential. Most of EnCana's land holdings were assembled at a time of lower commodity prices. More recently, the high-potential assets of Tom Brown, Inc. and Cutbank Ridge were added by acting on our competitive advantages. In the case of Tom Brown, we realized the potential of Colorado's Piceance basin. In the case of Cutbank Ridge, we applied special knowledge to unlock this play of huge, but previously under-estimated potential.

This means that the vast majority of our expenditures are high incremental return investments in a previously assembled resource base containing attractive exploitation potential. For example, our $4.2 billion 2005 exploitation program is expected to yield risk-adjusted, after-tax project rates of return averaging about 30 percent at prices around today's NYMEX futures market levels, and to yield cost of capital returns at average prices less than half of these levels. Disciplined investment in strong return projects combined with allocating surplus cash to reducing shares outstanding is designed to lift capital return metrics, while simultaneously building up the value of the company's underlying asset base.

Your management is committed to execution of these value creation principles. Chief Operating Officer Randy Eresman's Q&A section expands further on how these principles drive our capital investment decisions.

**HOW DID WE EXECUTE IN 2004?** Given the strengths EnCana brings to its business, our key challenges lie in execution. Once we have made the strategic decisions, then execution is everything. I've already talked about production and reserves growth, so how did our 2004 execution turn out financially?

In the upstream gas and oil industry, the key benchmark financial measure is cash flow per share. Cash flow was nearly $5.0 billion or $10.64 per share – up 14 percent. Operating earnings, which generally exclude many non-cash items not related to operations, were about $2.0 billion, or $4.22 per share – up 45 percent.

*We are confident that our existing land base and financial capacity are capable of sustaining internal 10 percent per share sales growth annually for at least five years to come.*

Net earnings were $3.5 billion, or $7.51 per share – up 53 percent. They included a large gain on the sale of our U.K. assets and were impacted by a number of unrealized non-cash mark-to-market adjustments. Most notably, the negative impact of the company's gas and oil hedges was offset by the positive impact of the strengthening Canadian dollar on our U.S. dollar denominated debt.

During 2004, EnCana shares traded in Canada earned a total return, including dividends, of 35 percent while U.S.-traded shares benefited from the strengthening Canadian dollar to earn a 46 percent total return.

**THE IMPACT OF PRICE RISK MANAGEMENT** The biggest negative factor in 2004 was the opportunity cost of our price risk management program, which resulted in a realized after-tax cash flow reduction of $708 million and an unrealized mark-to-market earnings reduction of $165 million after tax for hedging instruments beyond 2004.

EnCana has followed a disciplined risk management policy designed to mitigate the impact on cash flow of downward price movements through hedging half of our current year production at forward market prices. This also locks in important early stage returns on new capital investments.

Crude oil prices were driven by a confluence of upside events, including instability in key oil producing countries combined with unprecedented Asian demand growth, particularly in China.

The hedging cost of extreme world crude oil prices was magnified by a disconnect between the West Texas Intermediate (WTI) pricing benchmark and EnCana's heavier grades of crudes.

Going forward, we have adjusted our oil hedging strategy to favour instruments that provide a floor, but not a ceiling, on realized prices. Further, EnCana has entered into an arrangement with a U.S.-based refiner to assess the feasibility of refining EnCana's heavy oils into high value petroleum products.

**COMMODITY PRICE OUTLOOK** The world appears to have entered a period of energy demand growth, with a very small supply cushion to deal with both normal demand variations and unforeseen political or natural events. This may well mean both prolonged higher energy prices and more volatility. While world crude oil prices impact natural gas prices to the extent that gas competes with fuel oil in a portion of the market, natural gas prices are primarily driven by North American supply and demand. In this context, overall North American natural gas supply seems to have peaked and most observers agree that substantial relief from offshore liquefied natural gas or northern pipelines is five or more years away.

It would seem to be a very good time to be one of North America's largest, highest growth, lowest cost gas producers. We also believe that EnCana's ownership of the largest non-utility gas storage capacity will benefit from the strength of North American gas markets.

**ENCANA AS A PRINCIPLED, RESPONSIBLE CORPORATION** EnCana has adopted a unique **Corporate Constitution** which sets out principles and values that guide our behaviour as we pursue our vision of **energy for people**. Our Constitution is available on our Web site and I encourage investors to review it.

As we have seen all too often in both the private and public sectors, stating strong values and living by them are two different things. At EnCana, all employees, contractors and service providers are expected to live up to our Constitution – it is a living, vital part of our company. With the Corporate Constitution as a foundation, we have developed policies and practices that provide more specific guidance including our Corporate Responsibility Policy, our Community Investment Program and our Stakeholder Engagement Guide.

We aim for the highest levels of performance in these objectives, but we know from time to time breakdowns will occur. Some of our successes and our breakdowns are discussed in the Corporate Responsibility section. The key when breakdowns occur is to be open with stakeholders and do our best to deal with the impact of the situation. And to learn how we can do better. Our Constitution says: *"We manage risk of failure through disciplined, high-quality work and best judgement. Given these conditions, the sin is not failure itself, but failure to learn."*

**THE ACCOMPLISHMENTS OF ENCANANS** Every EnCana employee is responsible for preparing and obtaining supervisory approval of an annual High Performance Contract, which sets out both ongoing responsibilities and specific objectives for the year. These contracts form the basis for performance reviews, salary administration and variable compensation. The process cascades from my annual High Performance Contract, approved by the Board of Directors, and shared with all employees through our business units and corporate groups.

Looking back on 2004, EnCana's leadership is grateful for the skill and dedication with which EnCanans delivered both outstanding operational results and outstanding strategic progress. We have challenged our people to set high performance benchmarks, and we are very proud of their accomplishments for our shareholders . . . and all employees are shareholders. My Executive Team and I also want to extend gratitude to our highly engaged Board of Directors for their advice, wisdom, support and direction. Finally, on behalf of all employees and our Board, I want to express appreciation to shareholders for your confidence as we continue to build an unconventional high performance gas and oil company.

GWYN MORGAN
*President & Chief Executive Officer*
*February 23, 2005*

# THE FUTURE IS UNCONVENTIONAL

## 75% OF SALES FROM CONTINUING OPERATIONS TO COME FROM UNCONVENTIONAL


EnCana creates value primarily through the development of low-cost, long-life resource plays. In 2002, 50% of sales from continuing operations came from these resource plays. After the completion of planned divestitures, EnCana expects that in 2005, resource play sales will rise to 75% of sales.


| | 2002 (pro forma) | 2003 | 2004 | 2005F |
|---|---|---|---|---|
| **CONVENTIONAL ASSET DIVESTITURES** *($ millions)* | $450 | $2,300 | $3,700 | $3,000 ± |
| **ACQUISITIONS OF UNCONVENTIONAL ASSETS** *($ millions)* | $600 | $600 | $3,100 | |

**RESOURCE PLAY ATTRIBUTES**

- *Large-scale, long-life resources*
- *Low associated geological risk with predictable production over decades*
- *Well decline rates that flatten out over long producing lives*
- *Large consolidated blocks of 100%-owned lands*
- *Scalable operations/facilities and capital investment efficiencies*
- *Use of applied technology to continually improve performance*
- *Declining costs per well over time resulting from technical and operating learnings*
- *Long-term inventory of unbooked resource potential*

**RESOURCE PLAY FORMULA**

1. *Focus exploration because you find what you look for*
2. *Crack the technical nut*
3. *Control the land and infrastructure*
4. *Mitigate risks by engaging external stakeholders*
5. *Use large-scale, repeatable, manufacturing-style developments*
6. *Do lookbacks for continuous improvement*

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# UNCONVENTIONAL LEADERSHIP

**RESOURCE PLAYERS**

*It is tempting to think of resource plays only as assets. Yet EnCana's 10 key resource plays are worked by thousands of employees and a host of contractors, business partners and suppliers. Resource play assets are really only as good as the people who work them. People with vision to see long-term potential. And people with discipline to extract daily value. The steady development of EnCana's resource play assets is underpinned by two complementary notions – growth in potential and focus on results. Together, guided by these notions, people are strengthening EnCana's asset advantage. Together, they are creating new value.*

**THE ASSET ADVANTAGE**

*Large contiguous blocks of land have been strategically assembled for resource play development and reserve growth.*

## THE APPLIED TECHNOLOGY ADVANTAGE

*From poly-crystalline diamond compact bits to interlocking wooden mats, EnCana's innovative use of technology and its alliances with suppliers create meaningful benefits.*

### MATS FOR MUSKEG

*EnCana pushes technical boundaries, yet some innovations are quite simple. In northern B.C., the traditional drilling season has been short and intense – a few months between winter freeze-up and spring break-up. EnCana used a simple idea to help make drilling a year-round proposition – wooden mats. These mats, now built locally, are laid down for roadways and drill sites. The company can operate in muskeg and other sensitive terrain year-round. This seasonal leveling of activity also keeps local business partners working year-round.*

### A DRILLER'S BEST FRIEND

*EnCana invests a lot in drilling – in 2004, the company drilled about 5,000 net wells. At this level of activity, even modest per-well cost savings can add up. EnCana has worked closely with drilling contractors to use fit-for-purpose rigs and other applied technology to minimize drilling time. One example is the poly-crystalline diamond compact bit.*

### DRILL, COMPLETE, COMPLETE AGAIN

*Sometimes you don't have to drill a new well to produce more gas or oil. Sometimes you can re-enter an existing well bore and extract incremental production by re-stimulating formations and/or tapping into new horizons. EnCana has a vast inventory of wells, many of which can be re-completed using new techniques. In the company's Shallow Gas resource play, re-completions have helped increase production and reserves.*

EnCana

## THE ADVANTAGE OF SCALE

*The size and scope of EnCana's suite of resource plays in Canada and the United States create unique opportunities for cost efficiency, service-sector scheduling and sustainable growth.*

### PIPE DREAMERS

*EnCana drills and connects thousands of wells a year so it buys more pipe than any other oil and gas company in Canada. Enter the Steel Desk – EnCana's buying centre. The Steel Desk uses business units' drilling forecasts to capture volume discounts and saves money by purchasing steel directly from manufacturers.*

### STEALTH LAND BUY

*On September 22, 2003, EnCana announced the largest single-day purchase of petroleum and natural gas rights in the province of British Columbia – 325,000 net acres for $260 million. The culmination of a year of activity undetected by competitors, the deal carried work commitments only a large, experienced company could meet. Now it is the Cutbank Ridge resource play, spanning the B.C.-Alberta border with approximately 800,000 net acres.*

### VOLUME DISCOUNTS

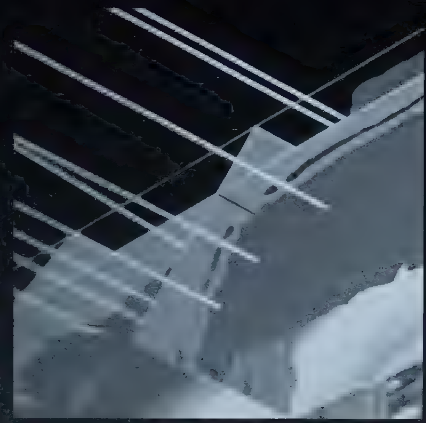
*EnCana's 10 key resource plays are extensive. The approach the company uses to exploit them is methodical, incremental and long-term. These factors make it possible and prudent for EnCana to enter into large, long-term arrangements with service-sector suppliers. Such arrangements lead to the increased familiarity and effectiveness of contractors working with the company's assets.*

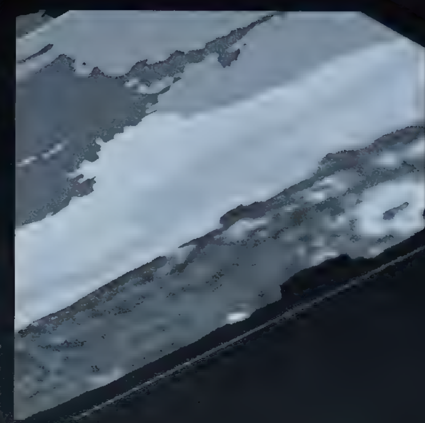
## THE KNOWLEDGE ADVANTAGE

*EnCana is developing the full potential of its resource plays by making competitive use of the knowledge of its people.*

### KNOWING YOUR ROCKS

*Earth scientists in EnCana's Shallow Gas resource play believe the saying, "It's hard to know where you're going if you don't know where you've been." To help shape development of these gas assets, they've built a multi-well, multi-decade database of production and reservoir information. This helps predict behaviours of wells to be drilled and wells to be re-completed. Using this knowledge, recovery rates have been increased. Reserves have grown. New value has been created from legacy assets.*






### GENERATE ENTHUSIASM

*EnCana uses a decentralized business unit model to foster an entrepreneurial and focused workforce. It can be challenging to share information and learnings across business units. So, gEnerate was created – an internal conference of more than 1,500 professionals. They gather to share knowledge – successes and failures – with each other. The information sharing continues long after the event.*

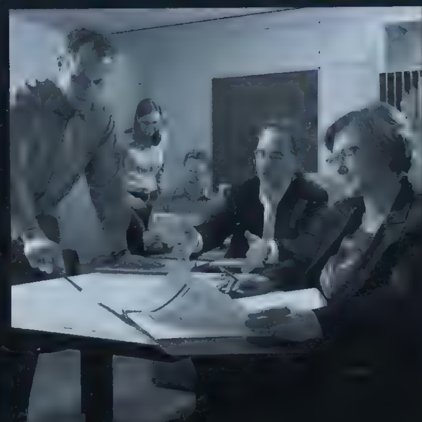
ENCANA.

## THE ADVANTAGE OF DISCIPLINE

EnCana's resource play approach to development and reserves growth is methodical and disciplined. It uses predictable, low-risk, manufacturing-style drilling and a disciplined focus on asset development.

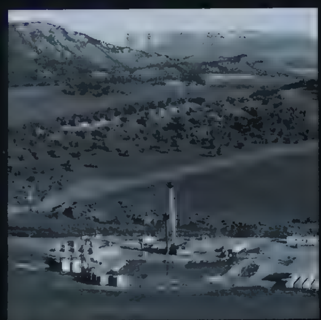
### [illegible]

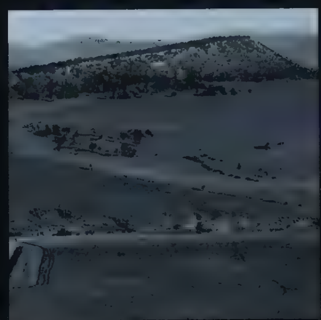
"A mountain is climbed one step at a time," the saying goes. EnCana finds this applies to many aspects of its business. The company has an ethic of operating prudence and risk reduction. Piloting is key. The Foster Creek SAGD resource play started as a pilot and is now in commercial operation. And in southern Alberta, EnCana has for three years tested the impact of reduced well spacing on reservoir performance – before taking it commercial.



### CHECKS AND BALANCES

EnCana has an extraordinarily strong portfolio of investment opportunities that are ranked to help ensure the greatest long-term profitability for the company. There are stringent internal hurdle rates, and every project must compete for capital through a rigorous project approval process. The thresholds favour long-life, strongly profitable projects. Capital investment in 2005 is expected to be 90 percent exploitation and 10 percent exploration.





### [illegible] FOR THE FUTURE

EnCana has positioned itself as the bellwether North American natural gas investment. Assets continue to be strategically assessed against this focus. In 2004, the company successfully acquired Tom Brown, Inc., sold its U.K. operations and put its Ecuador business and Gulf of Mexico assets on the market.

## CAN I SEE YOUR LICENCE?

EnCana's licence to operate. It's not only granted by the regulator. It's also granted by people living where the company operates and by people observing how it operates. It is critical for EnCana to know about the concerns and preferences of these stakeholders, and to respond. As part of the company's evolving corporate responsibility, effective community relations is a priority.


## THE ADVANTAGE OF PERSPECTIVE

*EnCana is emphasizing the unconventional, playing to its strengths, while also taking into account the perspectives of its stakeholders. As well, the company is mindful of market dynamics for natural gas and crude oil, economic growth in the United States and Canada, and altered global security.*

## ENERGY FOR PEOPLE

*EnCana has strategically reduced its international presence. With new perspective, the company is focusing on its industry leading inventory of unconventional continental resources to meet growing North American energy demand. EnCana is one of the largest sources of highly important natural gas for North American consumers and anticipates the market for natural gas will remain strong.*

ENCANA

Investor questions for EnCana's Chief Operating Officer Randy Eresman

*It's all about creating value by capitalizing on our unique competitive advantages.*

*Focused, disciplined execution is the key to solid results.*

# UNCONVENTIONAL EXECUTION

**Q EnCana has targeted 10 percent per share sales growth annually for the next several years. How do you determine the optimal volume growth rate?**

**A** The key determinant in establishing our long-term growth potential is the strength of our drilling inventory, measured in terms of size and economic viability, combined with the decline rate of our base assets. Our current inventory is capable of offsetting a 20 percent annual decline and growing production and reserves by 10 percent per year for the next five years. However, determining the optimal growth rate for a given year is a dynamic process. We take into consideration commodity prices, industry activity, the size and strength of our near-term investment opportunities, the company's financial position and the acquisition and divestiture marketplace.


Our objective is to maximize long-term net asset value (NAV) per share by balancing our core capital program with share purchases, demonstrating capital discipline on funding the highest return projects and undertaking exploration, acquisitions and divestitures as a means of strengthening our long-term potential.

**Q EnCana shifted its strategic focus in 2004 to concentrate on its North American assets. Why are you comfortable betting the company's future on North America when your peers are expanding internationally?**

**A** EnCana's asset base and operating expertise with unconventional resources is focused in North America because this is where we have the best opportunities to generate long-term, steady, profitable growth. Those companies focusing on international expansion are doing so because that is where they believe their opportunities lie.

Historically, North America's natural gas supply came largely from conventional reservoirs. However, we believe that the conventional business model for gas in North America has reached its tipping point. Declines from mature fields can no longer be offset with new conventional discoveries. The future for North American natural gas production lies in unconventional reservoirs – mainly tight gas sands, shale gas and coalbed methane. In fact, natural gas production from unconventional sources has been increasing to the point where it now represents about one third of total North American production. The unconventional natural gas potential is estimated to be far larger than the reserves discovered in conventional reservoirs to date. EnCana currently has one of the

largest onshore land positions, generally concentrated in contiguous tracts endowed with unconventional natural gas resources which we control and operate at close to a 100 percent basis. For North American oil, the future also resides in unconventional resources: the vast oilsands deposits of northeast Alberta.

North America is also one of the world's lowest risk areas to do business – having a highly developed marketplace with extensive infrastructure in place and transparent systems of law and regulation coupled with an attractive fiscal regime. Furthermore, the demand for North American natural gas is also rising and no external sources are expected to make any material supply impact through at least the end of this decade.

We are not alone in this view; we simply possess advantages given our land base and core competencies.

We will continue to target a select number of large domestic and international exploration prospects that are capable of adding significant option value. About 10 percent of our 2005 capital budget is directed towards exploration.

**Q What criteria do you use to ensure your resource plays are economic?**

**A** Every project within our portfolio of investment opportunities must compete for capital through a rigorous project approval process. Corporately we set a maximum amount of capital that could be made available annually; how much is actually dispersed depends on the strength of the overall portfolio.

We use well-defined economic hurdle rates to ensure that investment dollars are focused on the most profitable projects. Every project must meet multiple economic criteria. For instance, all exploitation projects must be capable of generating a go-forward rate of return that exceeds 20 percent and all long-term development projects, such as in-situ oilsands projects, and all exploration projects must exceed a rate of return of 15 percent – all on a fully risked basis.

We also stress test our projects by examining their supply cost, which is defined as the minimum price required to generate a return over the life of the project that exceeds our weighted average cost of capital. For 2005, the supply cost of our exploitation portfolio, which comprises 90 percent of our budget, is less than a $3.00 per thousand cubic feet NYMEX gas price for our gas projects, and less than a $20.00 per barrel WTI oil price for our oil projects. Clearly, highly economic returns are expected in the current price environment.

Our economics are fully risked to account for uncertainties related to timing, costs and performance. Furthermore, we adapt our current programs for learnings gathered from a comprehensive, disciplined review of all previously completed capital programs.

For 2005, as in previous years, all capital investment opportunities have been evaluated and ranked. Our exploitation portfolio is extremely attractive, with a capital weighted rate of return exceeding 30 percent, similar to the returns that were achieved in 2003 and 2004.

**Q Based on historical metrics, did you pay too much for Tom Brown, Inc.?**

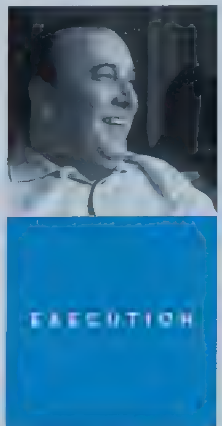
**A** We believe our acquisition of Tom Brown was well timed and will create long-term value for our shareholders. The Tom Brown assets were a perfect fit with EnCana's North American natural gas resource play focus and with our existing U.S. Rocky Mountain and Texas assets. Since the transaction there has been a further strengthening of the long-term North American natural gas price outlook. As well, subsequent industry transactions for resource play assets have been completed at valuations reflecting the strength of the market and the significant growth potential of resource play assets.

Acquisitions of growth assets will almost always tend to appear expensive at the time of the transaction since much of the value is in the future potential. We believe EnCana has consistently demonstrated its ability to create value

from these types of assets specifically in places like the U.S. Rockies, where a majority of the Tom Brown assets reside.

**Q What role has technology played in making resource plays viable? Is this technology proprietary to EnCana?**

**A** Technological advances, particularly in drilling and completions, together with higher natural gas and oil prices, have made a huge impact in making resource plays more attractive and profitable. Many of the plays we pursue today use technologies unavailable just five years ago.




While most of the pure technology we use in resource plays is not proprietary to EnCana, finding and supporting the development of the right technology for each play is a significant success factor. Virtually every resource play requires some variation in the application of the available technologies to obtain the best results.

EnCana's advantage lies in our 30-year experience with unconventional reservoir development and the scale at which our land holdings allow us to apply our knowledge to resource play development over long periods of time.

**Q How does your resource play formula work and create value?**

**A** Resource plays require extensive experimentation with drilling and completion technology to find the key that unlocks their potential. Once we've achieved that, it's all about execution.

Resource play development generally requires large-scale repeatable drilling programs that lend themselves to continuous improvement because the programs by their nature are conducted over many years.

The application of scale and technology, combined with continuous learning, drives down both capital and operating costs and increases per-well reserve recoveries.

Resource plays have highly predictable and reliable production profiles, often sustained for decades. As a result, we often use the phrase "dial it in" meaning the performance is so predictable, we just have to determine the number of wells that we want to drill each year to determine the resulting production and growth rate from these plays.

**Q Natural gas is clearly your focus. How do your oilsands projects fit with the overall strategy?**

**A** The Athabasca oilsands are a world class resource extending over much of northeast Alberta, with hundreds of billions of barrels in place. EnCana's lands contain an estimated 40 billion barrels of bitumen in place, from which we've high-graded several sites where steam-assisted gravity drainage (SAGD) technology can be used to commercially extract up to several billion barrels of bitumen. To date, our commercial efforts have been focused at Foster Creek, the industry's leading SAGD project which is being expanded from 30,000 to 60,000 barrels per day by the end of 2006. EnCana's long-term production potential from its lands is estimated to be in the range of 200,000 barrels per day. Our in-situ oilsands are a very large resource play where we believe the continued application of technology will enable the continued improvement in returns over time. Today, EnCana's Foster Creek project enjoys the lowest operating costs in the industry.

**Q Increased activity in the gas and oil sector has put cost pressures on equipment and services. How has this impacted EnCana and what are your plans to mitigate these rising costs?**

**A** Our costs rose about 5 percent overall in 2004 – mainly from increasing day rates for drilling and other service costs, rising steel prices and the higher Canadian dollar relative to the U.S. dollar. For 2005, we expect capital costs could be up by another 5 to 10 percent due to continued inflationary pressures, as well as currency impacts.

To offset inflationary increases in both capital and operating costs, we strive to introduce new efficiencies each year. Continuous improvement in our large-scale, repetitive resource play exploitation programs is the major contributor to maintaining or reducing our cost structure with time.

Our strategy of focusing our activity and developing long-term resource management plans allows us to work with our contractors and suppliers to manage our costs and benefit from economies of scale.

We are keenly aware that the pace of our programs has the potential to cause localized inflation, so maintaining the flexibility to slow down or speed up our activity, as warranted, is a key part of our operations strategy.

**Q What are some of the key challenges you face as you implement your resource play strategy?**

**A** Resource play developments require large numbers of wells to be sited, drilled, completed and tied-in to gathering systems each year. Executing this high level of activity is the key to our success.

We strive to maintain our licence to operate in good standing, which enables us continued access to conduct our activities by being a good neighbour, operating safely and caring for the environment. Maintaining a large enough inventory and planning well in advance provide flexibility and choices which inevitably lead to better decisions as we implement our programs.

**Q Will EnCana be able to continue to grow its gas resource potential? Where will that growth take place?**

**A** We believe that with future technology developments and a sustained natural gas price environment above $4.00 per thousand cubic feet, EnCana will be able to continue to grow its natural gas resource potential in North America for a very long time. This growth will be principally in the deep basin or continuous gas environments in Western Canada, the U.S. Rockies and Texas.

**Q Why does EnCana have all of its reserves evaluated by independent qualified reserve evaluators?**

**A** Reserves are the foundation of a gas and oil company, and we believe that the external assessment of reserves is just as important as the external assessment of financial statements. For this reason, we have 100 percent of our reserves externally evaluated every year. We believe this provides the highest level of scrutiny for our shareholders and is a vital part of our lookback and learning process for our business leaders.

**Q What will the company look like in five years?**

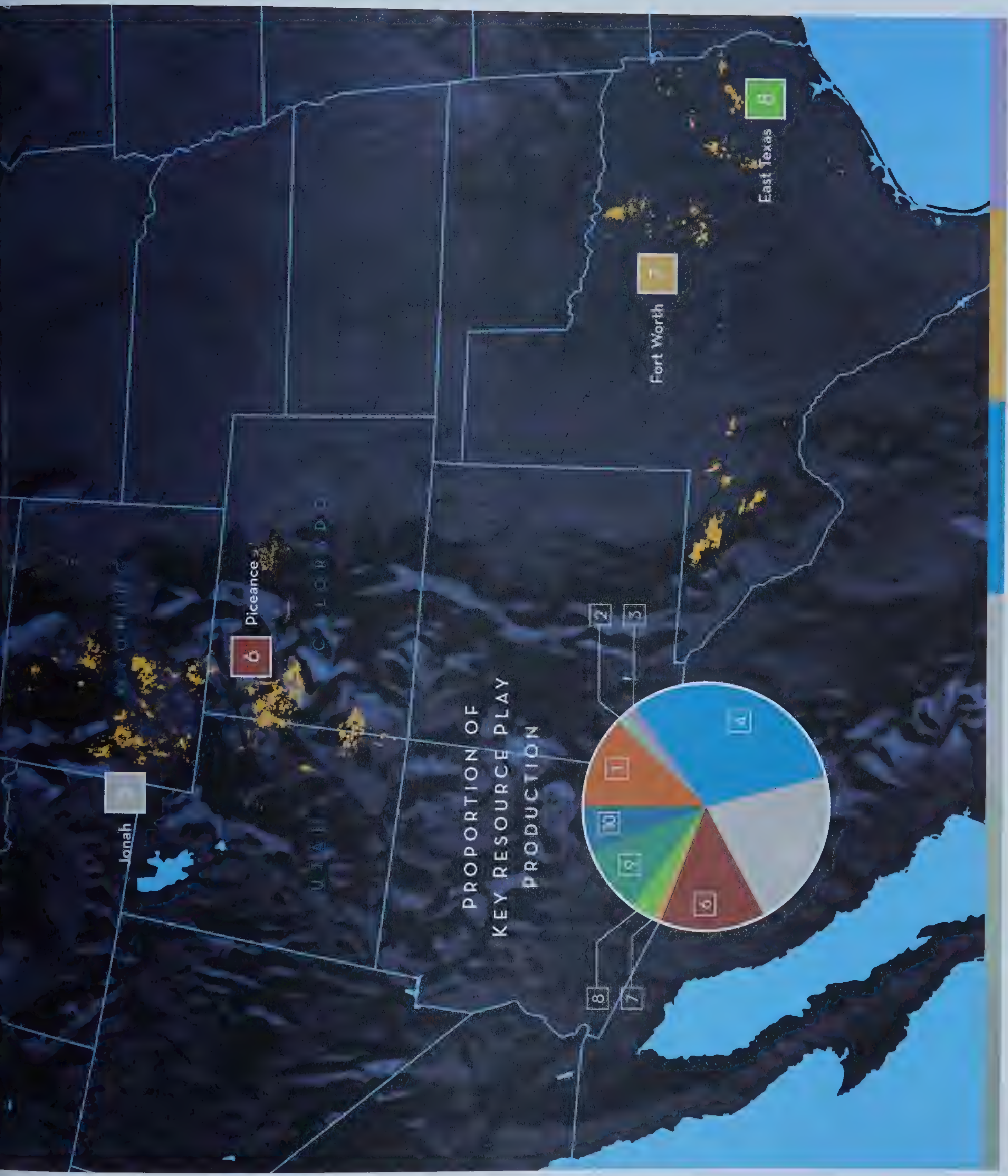
**A** In five years, EnCana will be an even more focused natural gas and in-situ oilsands resource play company.

More than 80 percent of our production will come from resource plays, our decline rate will be among the lowest in the industry and our sales growth per share will be among the highest. There will be clear, long-term potential for the company to continue to add value over time.

EnCana will continue to high grade its portfolio to be more focused on our key resource plays where we can provide more profitable growth for our shareholders.

RANDY ERESMAN
*Chief Operating Officer*


ENCANA
FOCUSED ON
NORTH AMERICA
1 Greater Sierra
2 Cutbank Ridge
3 Coalbed Methane
4 Shallow Gas
9 Foster Creek
10 Pelican Lake


PROPORTION OF
KEY RESOURCE PLAY
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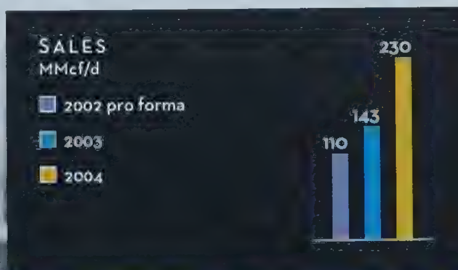
ENCANA

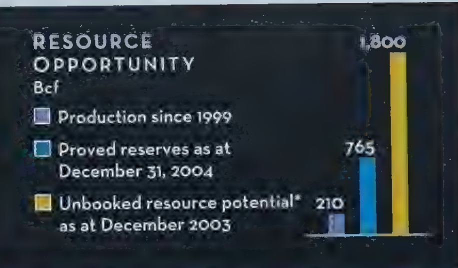
# RESOURCE PLAY PORTFOLIO

*North American assets are highlighted by 10 key resource plays. These resource plays – all at differing stages of maturity – combine to provide a growing percentage of the company's performance and potential.*

RESOURCE PLAY

1




## GREATER SIERRA

*Natural gas, northeast British Columbia, initiated in 1999*

*Greater Sierra was EnCana's first resource play in northeast B.C. Horizontal wells utilizing underbalanced drilling techniques target the Jean Marie geological formation. EnCana has to date developed less than 20 percent of the 2.8 million net acres it controls of this long-life property.*

*Until recently, Greater Sierra drilling was restricted to the winter season. EnCana now deploys wooden mats across the marshy landscape during summer to complete multi-well programs.*

*This has reduced costs, leveled activity over the seasons, and helped keep skilled and knowledgeable crews working year-round.*

### Performance

**2004**

- *Produced an average of 230 MMcf/d, up 61 percent from 143 MMcf/d in 2003*
- *Drilled 187 net wells*
- *Invested $475 million*
- *Proved reserves of 765 Bcf*
- *Operating costs of $0.43/Mcf*
- *Employed 3-D seismic to help solve technical complexities of non-continuous porosity in reservoirs*

### Plans and Potential

**2005 Forecast**

- *Average production: 250 MMcf/d*
- *Capital investment: $390 million*
- *Net wells: 195*

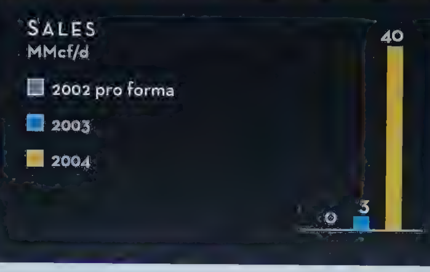
**Beyond**

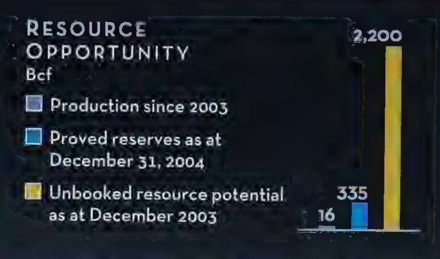
- *Unbooked resource potential: 1.8 Tcf*
- *Five-year drilling inventory: 1,000 wells*

** Unbooked resource potential is a term used by EnCana to refer to the estimated quantities of hydrocarbons that may be added to proved reserves over a five-year time frame largely from a specified resource play or plays. Unbooked resource potential is provided for resource plays 1 to 10 in the resource play portfolio.*

RESOURCE PLAY

2




## CUTBANK RIDGE

*Natural gas, north-east British Columbia, acquired in 2003*

*EnCana captured the Cutbank Ridge resource play in 2003 with the largest single-day land purchase ever made in B.C. – 325,000 net acres. The company now holds about 800,000 net acres on the play.*

*Cutbank Ridge targets primarily the Cadomin geological formation using horizontal drilling and open-hole stimulation techniques which, in combination, have generated attractive results. As the Cadomin formation runs west into B.C., this gas-charged rock thickens, in places, up to 300 feet.*

*Accessible year-round, Cutbank Ridge contains several prospective zones above and below the Cadomin that can be precisely identified and drilled using 3-D seismic.*

*Several pipelines and gas processing plants serve the area, enabling gas from new wells to reach markets quickly.*

*Through its Oil and Gas Development Strategy, the Government of British Columbia established targeted royalties, fiscal reforms, infrastructure incentives and regulatory streamlining. This created a vibrant and competitive environment that has helped EnCana expand its potential in northeast B.C.*

### Performance

**2004**

- *Produced an average of 40 MMcf/d, up from 3 MMcf/d in 2003*
- *2004 exit rate of 47 MMcf/d*
- *Drilled 50 net wells*
- *Invested $225 million*
- *Proved reserves of 335 Bcf*
- *Operating costs of $0.41/Mcf*
- *Continued to build relationships with local and aboriginal communities*
- *Continued to address technical challenges experienced when drilling and fracturing horizontal wells in a hard conglomerate formation*

### Plans and Potential

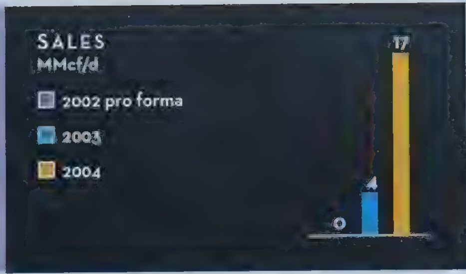
**2005 Forecast**

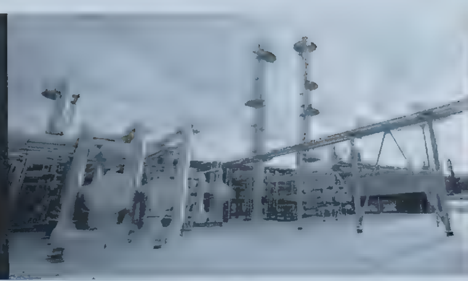
- *Average production: 75 MMcf/d*
- *Capital investment: $280 million*
- *Net wells: 100*

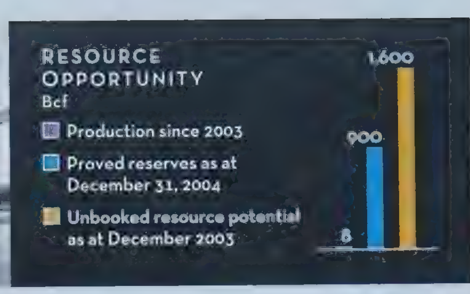
**Beyond**

- *Unbooked resource potential: 2.2 Tcf*
- *Five-year drilling inventory: 800 wells*

RESOURCE PLAY 3






## COALBED METHANE

*Natural gas, Palliser block, south central Alberta, initiated sales in 2003*

*EnCana's Coalbed Methane (CBM) resource play has been guided by the company's multi-decade experience in southern Alberta shallow gas operations. After more than 30 years of producing gas from shallow depths trapped in porous rock formations, EnCana is unlocking new unconventional horizons – shallow gas trapped in microscopic cracks within coal seams.*

*Potential from this resource base is substantial. The company has drilled 844 net wells since the start of 2003.*

*With extensive gas gathering pipelines and processing facilities already in place from shallow gas development, CBM production can be efficiently and economically brought on stream. In addition, some existing well bores are being re-completed to produce gas from both sands and coal.*

*Most of EnCana's CBM activity is focused on the dry coal seams of the Horseshoe Canyon formation.*

### *Performance*

**2004**

- *Produced an average of 17 MMcf/d, up from 4 MMcf/d in 2003*
- *2004 exit rate of 30 MMcf/d*
- *Drilled 577 net wells*
- *Invested $151 million*
- *Proved reserves of 900 Bcf*
- *Operating costs of $0.48/Mcf*
- *Held stakeholder consultations and engaged regulators to facilitate approvals for access*

### *Plans and Potential*

***2005 Forecast***

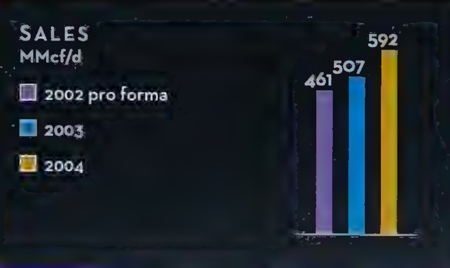
- *Average production: 60 MMcf/d*
- *Capital investment: $200 million*
- *Net wells: 1,000*

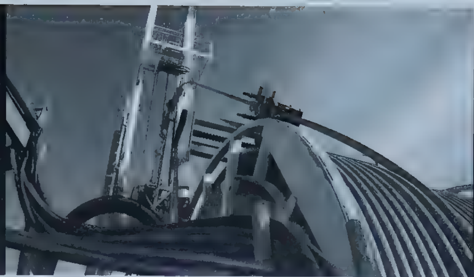
***Beyond***

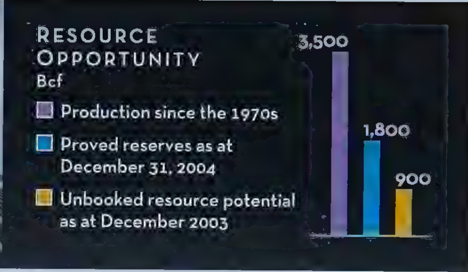
- *Unbooked resource potential: 1.6 Tcf*
- *Five-year drilling inventory: 5,500 wells*

RESOURCE PLAY

4






## SHALLOW GAS

*Natural gas, southeast Alberta, legacy assets produced for decades and still growing*

*The Shallow Gas resource play is the oldest, largest, and most profitable in EnCana's portfolio. Much of what EnCana has learned about resource plays comes from this play.*

*In 2004, the company's cumulative production from the Suffield area within this prolific natural gas play surpassed 2 trillion cubic feet of gas – more than the original estimate of ultimate recoverable reserves. After more than 30 years, the Shallow Gas resource play production is at record levels, and is largely contained in two contiguous blocks covering about 3.5 million net acres.*

*EnCana has developed an expansive data bank of well and reservoir information over the years and, as a result, well performance is highly predictable.*

*Since the mid 1980s, the company has generally reduced or maintained costs and improved drilling and completion performance. Drilling and completion equipment has become lighter and more mobile; this has helped to increase efficiencies and decrease the environmental footprint of operations.*

### Performance

**2004**

- *Produced an average of 592 MMcf/d, up 17 percent from 507 MMcf/d in 2003*
- *Drilled 1,552 net wells*
- *Invested $385 million*
- *Proved reserves of 1.8 Tcf*
- *Operating costs of $0.41/Mcf*

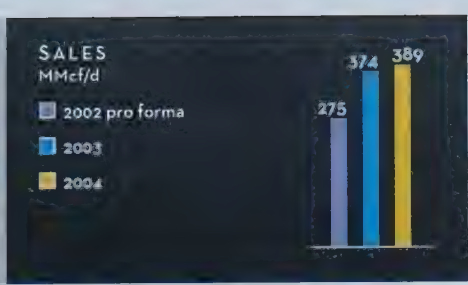
### Plans and Potential

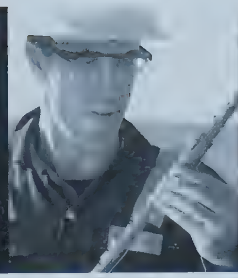
**2005 Forecast**

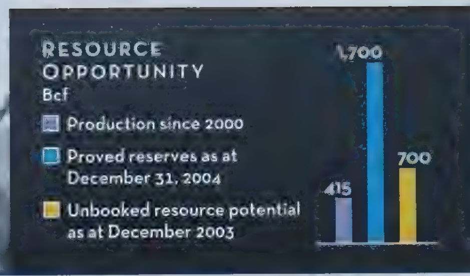
- *Average production: 650 MMcf/d*
- *Capital investment: $275 million*
- *Net wells: 1,400*

**Beyond**

- *Unbooked resource potential: 900 Bcf*
- *Five-year drilling inventory: 6,500 wells*




## JONAH

*Natural gas, southwest Wyoming, acquired in 2000*

*The Jonah resource play represents EnCana's initial entry into the U.S. Rockies region. EnCana added to its interest in the property in 2002 and now owns about 75 percent of the field.*

*Since arriving in 2000, EnCana has doubled both reserves and production – mainly through a powerful combination of infill drilling and advanced well fracturing techniques.*

*This approach has enabled the company to access the prolific store of natural gas in the Lance formation that makes up the Jonah play. These stacked sands exist at depths between 8,000 and 11,500 feet.*

*A methodical program of infill drilling has proven to be a success, with the average infill well producing almost as much as the offsetting existing wells.*

*EnCana is expecting the U.S. Bureau of Land Management to conclude its Environmental Impact Statement (EIS) covering future development by late 2005, which is expected to open the door for production growth at Jonah.*

### *Performance*

**2004**

- *Produced an average of 389 MMcf/d, up 4 percent from 374 MMcf/d in 2003*
- *Production growth restricted due to pending EIS decision*
- *Drilled 70 net wells*
- *Invested $164 million*
- *Proved reserves of 1.7 Tcf*
- *Operating costs of $0.14/Mcf*
- *Received state regulatory approval for 10-acre spacing of down-hole locations, which results in the potential for 1,800 additional wells*

### *Plans and Potential*

**2005 Forecast**

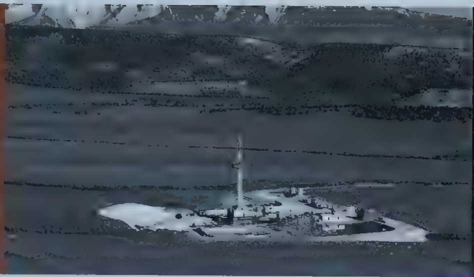
- *Average production: 415 MMcf/d*
- *Capital investment: $315 million*
- *Net wells: 130*

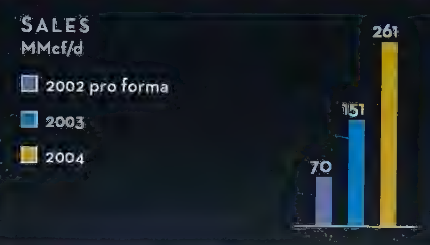
**Beyond**

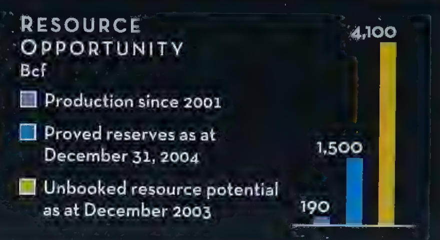
- *Unbooked resource potential: 700 Bcf*
- *Five-year drilling inventory: 800 wells*

RESOURCE PLAY

6






## PICEANCE

*Natural gas, Colorado, acquired in 2001*

*The Piceance basin is one of EnCana's fastest growing and highest potential plays. EnCana entered the Piceance basin in 2001 by acquiring the Mamm Creek field, where production has increased significantly. EnCana added to its position in the basin with its 2004 acquisition of Tom Brown, Inc. The company now holds more than 795,000 net undeveloped acres, more than four times its 2001 acreage.*

*The Piceance basin is characterized by thick gas accumulations primarily in the Williams Fork formation. The nature and extent of these accumulations make this an ideal resource play – a location where the company can methodically apply technology to increase recovery and reduce costs.*

*One example of technology is micro-seismology which has helped to optimize completion designs and well spacing.*

*Given the strong growth potential of the Piceance basin, current infrastructure in the region is not expected to be adequate. With this in mind, EnCana is building a new regional pipeline, the Entrega Pipeline. Pending regulatory approvals, Entrega is slated to come on stream in late 2005. Entrega will enable EnCana to continue to increase production out of the Piceance basin.*

### *Performance*

**2004**

- *Produced an average of 261 MMcf/d, up 73 percent from 151 MMcf/d in 2003*
- *Drilled 250 net wells*
- *Invested $440 million*
- *Proved reserves of 1.5 Tcf*
- *Operating costs of $0.46/Mcf*
- *Redeployed rigs from Mamm Creek to other areas of the Piceance basin to address stakeholder concerns about the level of activity in the area*

### *Plans and Potential*

***2005 Forecast***

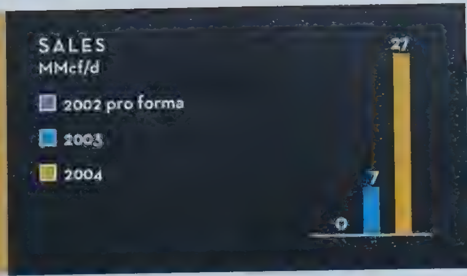
- *Average production: 330 MMcf/d*
- *Capital investment: $460 million*
- *Net wells: 330*

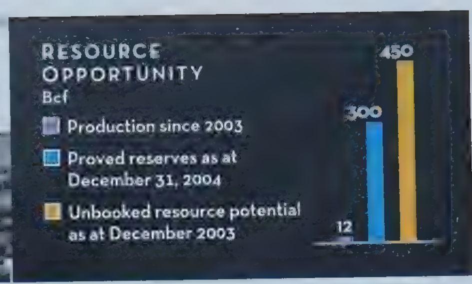
***Beyond***

- *Unbooked resource potential: 4.1 Tcf*
- *Five-year drilling inventory: 3,400 wells*

RESOURCE PLAY

7




## FORT WORTH

*Natural gas, north Texas, acquired in 2003*

*EnCana has assembled a strong land position in the prolific Barnett Shale play in the Fort Worth basin.*

*Including an acquisition made late in 2004, the company has about 130,000 net acres of undeveloped land. EnCana is applying horizontal drilling and multi-stage reservoir fracturing to unlock the potential of one of the company's newest resource plays.*

### *Performance*

**2004**

- *Produced an average of 27 MMcf/d, up from 7 MMcf/d in 2003*
- *Drilled 36 net wells*
- *Invested $58 million*
- *Proved reserves of 300 Bcf*
- *Operating costs of $0.73/Mcf*

### *Plans and Potential*

**2005 Forecast**

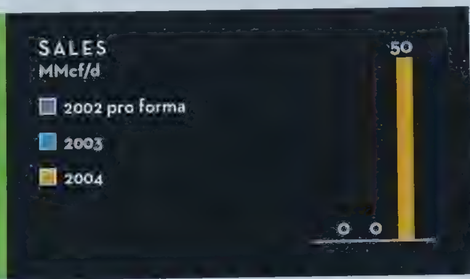
- *Average production: 90 MMcf/d*
- *Capital investment: $150 million*
- *Net wells: 85*

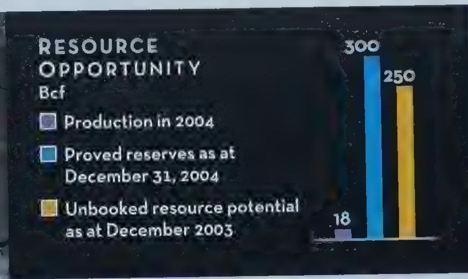
***Beyond***

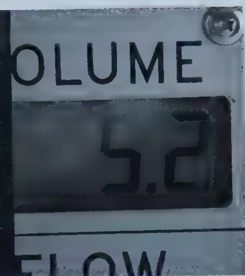
- *Unbooked resource potential: 450 Bcf*
- *Five-year drilling inventory: 500 wells*

RESOURCE PLAY

8




## EAST TEXAS

*Natural gas, east Texas, acquired in 2004*

*This new resource play, targeting the Bossier and Cotton Valley zones, was acquired as part of the Tom Brown, Inc. acquisition.*

*East Texas has similar characteristics to other resource plays in the U.S. Rockies and in Canada. It is a tight gas, multi-zone play that requires careful application of technology to unlock the gas.*

### *Performance*

**2004**

- *Produced an average of 50 MMcf/d*
- *Drilled 50 net wells*
- *Invested $108 million*
- *Proved reserves of 300 Bcf*
- *Operating costs of $0.57/Mcf*

### *Plans and Potential*

**2005 Forecast**

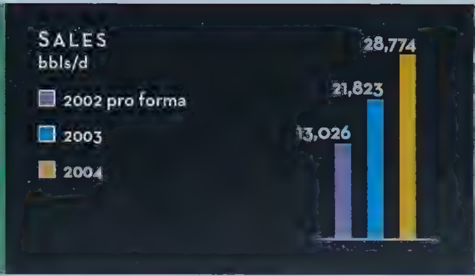
- *Average production: 110 MMcf/d*
- *Capital investment: $185 million*
- *Net wells: 85*

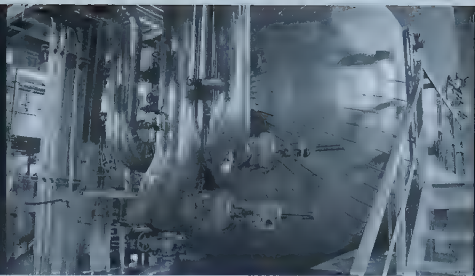
***Beyond***

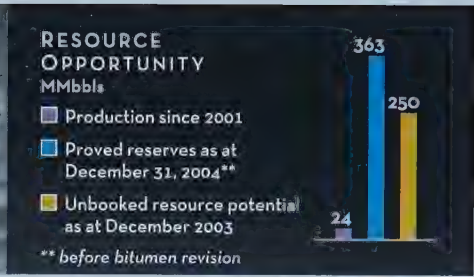
- *Unbooked resource potential: 250 Bcf*
- *Five-year drilling inventory: 250 wells*

RESOURCE PLAY

9






## FOSTER CREEK

*In-situ oilsands, northeast Alberta, commenced commercial operations in 2001*

*Foster Creek is the quintessential resource play – a high-quality, unconventional resource with large potential and scalable, repeatable operations that enable the company to incorporate technical advances.*

*Foster Creek produces from the McMurray formation of the Athabasca oilsands, and features a technology called steam-assisted gravity drainage (SAGD). The company conducted a multi-year pilot prior to starting commercial operations in 2001.*

*In SAGD, horizontal wells are drilled in pairs – running parallel above one another about 17 feet apart. Steam is injected in the upper well to warm the bitumen and make it less viscous so it can drain to the lower production well bore. A critical SAGD thermal efficiency measure is the ratio between the quantity of steam injected and the quantity of oil produced. EnCana's steam-oil ratio of 2.5 times is industry leading.*

*With a high-quality reservoir and leading thermal efficiency, Foster Creek delivers excellent returns.*

### Performance

**2004**

- *Produced an average of 28,774 bbls/d, up 32 percent from 21,823 bbls/d in 2003*
- *Drilled 11 net wells*
- *Invested $145 million*
- *Operating costs of $8.90/bbl*
- *Year-end bitumen prices were impacted by unusually wide differentials and high diluent costs. As a result and in accordance with SEC regulations, 363 million barrels were removed from proved reserves. In January 2005, prices had recovered to the point that the revision would not have occurred.*

### Plans and Potential

**2005 Forecast**

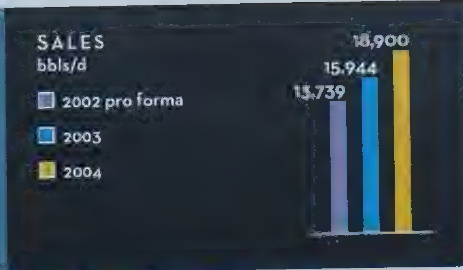
- *Average production: 33,000 bbls/d*
- *Capital investment: $200 million*
- *Net wells: 12*
- *10,000 bbls/d expansion to be completed late 2005*

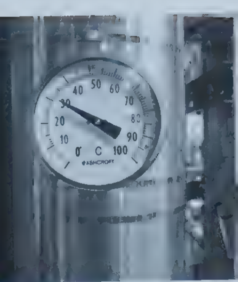
**Beyond**

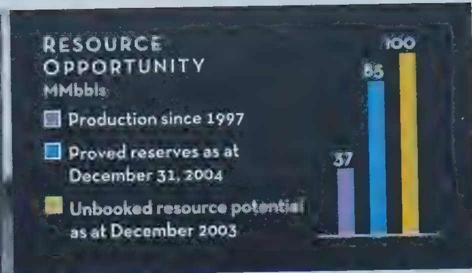
- *20,000 bbls/d expansion to be completed late 2006, taking total production to 60,000 bbls/d*
- *Unbooked resource potential: 250 MMbbls*
- *Five-year drilling inventory: 200 wells*

RESOURCE PLAY

# 10






## PELICAN LAKE

*Heavy oil, northeast Alberta, acquired in 1997*

*With about one billion barrels of water floodable heavy oil in place, the Pelican Lake development started with primary production, which is capable of recovering about six percent of the oil in place. EnCana's application of waterflood techniques is expected to increase recovery to about 12 percent.*

### Performance

**2004**

- *Produced an average of 18,900 bbls/d, up 19 percent from 15,944 bbls/d in 2003*
- *Drilled 92 net wells*
- *Invested $117 million*
- *Proved reserves of 85 MMbbls*
- *Operating costs of $4.03/bbl*

### Plans and Potential

**2005 Forecast**

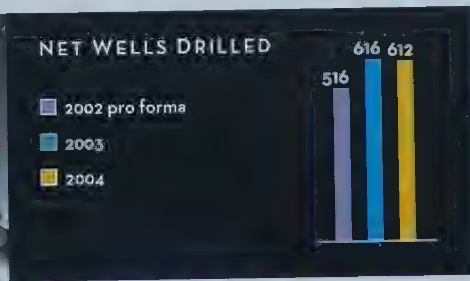
- *Average production: 29,000 bbls/d*
- *Capital investment: $85 million*
- *Net wells: 72*

**Beyond**

- *To further improve this recovery rate, EnCana is testing the injection of chemical polymers which may take recovery rates towards 20 percent*
- *Unbooked resource potential: 100 MMbbls*
- *Five-year drilling inventory: 40 wells*

EXPLORATION

# E




*EnCana invests about 10 percent of its annual upstream capital budget exploring for new reserves. Most exploration involves the piloting of existing and new resource plays to extend or define the boundaries. The company also conducts a high-impact exploration program in a series of select international and frontier locations.*

### Performance

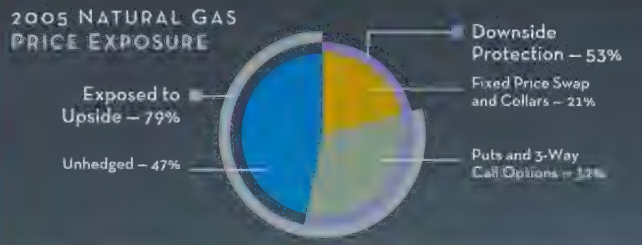
- *In 2004, EnCana made significant discoveries onshore North America among its resource plays and in the frontier regions. As well, it achieved encouraging results in several international locations.*

### Plans and Potential

- *In 2005 and beyond, EnCana will delineate the 2004 discoveries and continue to seek out high-impact exploration opportunities, primarily in North America, but also in select international regions.*

## MIDSTREAM & MARKETING

M





*Optimize netbacks for growing production volumes from North American resource plays*

*The primary responsibility of EnCana's Marketing group is to sell its proprietary volumes at regional liquid market hubs or in downstream markets that provide the best possible netback.*

*Marketing also monitors and analyzes North American gas and world crude oil fundamentals that support EnCana's capital investment decisions and drive strategies for sales and long-term transportation commitments.*

*EnCana's Midstream group is focused on gas storage, natural gas liquids extraction and power generation. Midstream initiatives create value through third-party contracting, product sales and supporting EnCana's upstream operations.*

*EnCana is the largest independent owner and operator of natural gas storage capacity in North America, at a time when the gas market is becoming increasingly dependent on gas storage to meet seasonal and short-term demand peaks and to manage gas price volatility.*

### Performance

#### Marketing

- Agreed to examine the feasibility of a long-term joint venture with U.S. refiner, Premcor, focused on upgrading EnCana's bitumen production, mitigating the impact of widely fluctuating price differences between Canadian heavy oil and North American light oil benchmarks
- Developed new heavy oil blend – Western Canada Select – to advance sales and competitiveness of Canadian heavy oil in U.S. markets

#### Midstream

- Initiated the Entrega Pipeline to expand gas market access for Piceance resource play growth
- Submitted application to U.S. federal regulator for proposed Starks gas storage facility in Louisiana
- Grew total gas storage capacity to 163 billion cubic feet through investments in the Countess gas storage facility in Alberta and the Wild Goose storage facility in California, compared with 134 billion cubic feet in 2003

### Plans and Potential

#### Marketing

- Continue to work with Premcor to determine feasibility of adding conversion to its Ohio refinery. This is expected to provide the lowest cost upgrading solution towards monetizing EnCana's significant oilsands resource play

#### Midstream

- Seek regulatory certification of Entrega Pipeline to begin to unlock the resource potential of the Piceance basin
- Focus on increasing diluent supply for heavy oil transportation requirements
- Expand Countess gas storage capacity by another 10 billion cubic feet
- Seek regulatory approval and market support to develop the Starks salt cavern storage project, with 9 billion cubic feet of capacity by 2006 and 19 billion cubic feet by 2007

THE WAY ENCANA DOES BUSINESS

# A COMMITMENT TO CORPORATE RESPONSIBILITY

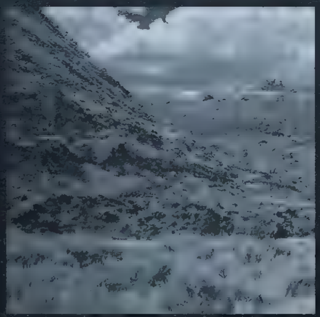

EnCana defines corporate responsibility as a commitment to provide strong leadership, value creation and prudent governance, as well as ensuring support for human rights, fair labour practices, strong environment, health and safety practices, stakeholder engagement and community development. The company's commitment to corporate responsibility applies to everything it does, everywhere it operates.


## INVESTMENT IN EDUCATION

*EnCana supports education and skills development in remote communities by helping fund two mobile education units used by the Northern Alberta Institute of Technology to provide training where it is needed. Each mobile unit is equipped to support the delivery of curriculum ranging from business to trades-related programs such as electrical, pipe trades and welding.*

## ABORIGINAL PARTNERSHIP

*A partnership was forged with the Fort Nelson First Nation, resulting in the first ownership and operation of a drilling rig by a B.C. First Nation. Liz Logan, Chief of the Fort Nelson First Nation at the time the partnership was created, stands in front of the rig.*



## STAKEHOLDER ENGAGEMENT

*EnCana's Horseshoe Canyon Coalbed Methane (CBM) resource play is a relatively new and unconventional source of natural gas. In order to provide full operational information and address local concerns, EnCana hosts frequent open houses, field tours, town hall and community awareness meetings to share information on development plans and receive feedback from area residents.*

## THE WAY ENCANA DOES BUSINESS: A COMMITMENT TO CORPORATE RESPONSIBILITY

EnCana is guided by the values and shared principles set out in the company's **Corporate Constitution**. From this founding document, EnCana adopted a Corporate Responsibility Policy that contains clear commitments which define the way the company and its people do business.[1] EnCana is committed to conducting business ethically, legally, and in a manner that is fiscally, environmentally, and socially responsible, while delivering sustainable value and strong financial performance. EnCana defines corporate responsibility as a commitment to provide strong leadership, value creation and prudent governance, as well as supporting human rights, fair labour practices, strong environment, health and safety practices, stakeholder engagement and community development. **The company's commitment to corporate responsibility applies to everything it does, everywhere it operates.**

EnCana's approach to reporting is to discuss its corporate responsibility performance in the company's annual report, on its Web site and by providing information of specific interest to the communities where the company operates.

To meet the numerous challenges in the natural gas and oil industry, EnCana employs integrity, innovation and adaptability as it develops and implements efficient and effective solutions. The following provides a snapshot of the company's performance in meeting the inherent industry challenges and in living up to its constitutional principles and Corporate Responsibility Policy. The company's commitment to and demonstration of corporate responsibility is also addressed throughout other sections of the annual report.

## IMPLEMENTING CORPORATE RESPONSIBILITY EVERYWHERE ENCANA OPERATES

**Operating staff in each of EnCana's business units are accountable for ensuring that the company's corporate responsibility commitments are implemented.**

To reach a staff of more than 6,000 employees and contractors, spread across 70 locations, a company-wide corporate responsibility training program was instituted in March 2004, using an innovative combination of on-line tools and face-to-face sessions. Training does not stop with staff. Existing and potential suppliers and contractors are expected to know and uphold EnCana's values and policies. Workshops are held for contractors and suppliers on company expectations.

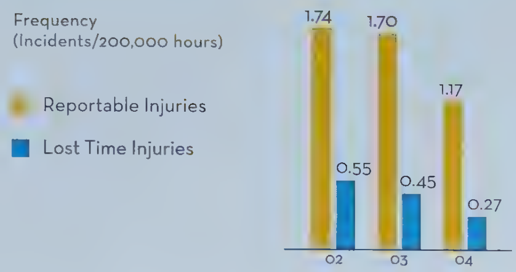
During 2004, EnCana delivered training to employees on the Corporate Responsibility Policy and introduced or enhanced other practices including:

- Alcohol and Drug Policy;
- Environment, Health & Safety Best Practices;
- Business Conduct & Ethics Practice;
- Non-Harassment and Business Conduct & Ethics training; and
- Stakeholder Engagement Guide.

*Monitoring conformance* EnCana provides an effective and consistent procedure to address potential violations of company policies or practices, and other regulations. The company has established an Investigations Committee, which has representatives from EnCana's audit, human resources, information technology, legal and security groups. All complaints brought to the attention of the committee are reviewed. Some complaints are forwarded to the business units for resolution. Others, if appropriate, are investigated in a confidential and timely fashion in accordance with EnCana's Investigations Practice. Corrective action is taken when complaints are found to have merit. In 2004, 39 concerns were addressed, an increase from seven in 2003. The increase is attributed to confidence in the practice, greater education and awareness of the means for redress. Corrective action was taken or is ongoing on 12 cases where complaints were found to have merit.

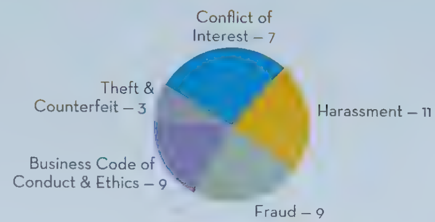
[1] Policies are published on www.encana.com

## IMPROVING OPERATIONAL SAFETY




*EnCana considers the health and safety of its workers a high priority.*

## INVESTIGATING BUSINESS CONDUCT AND ETHICS




*Internal and external stakeholders can raise concerns to EnCana's Investigations Committee about potential violations of company policies and practices. In 2004, the committee investigated 39 complaints.*

## DEVELOPING INNOVATIVE SOLUTIONS

99.8%

*Phase I of the International Energy Agency GHG Project concluded that 99.8 percent of $CO_2$ injected in the Weyburn field will remain stored underground for at least 5,000 years.*

*Monitoring environment, health and safety* EnCana conducts internal environment, health and safety (EH&S) audits within the business units to ensure compliance with the EH&S management system and regulations. Audit findings are shared with staff so that immediate improvements can be implemented. The audits also generate reports to track compliance and monitor progress, with material findings of non-compliance being reported to the Corporate Responsibility, Environment, Health and Safety Committee of the Board of Directors. In 2004, there were no material audit findings of non-compliance.

A corporate EH&S audit program was developed with strategic direction from Pilko and Associates, a leading management consultant firm. This program will be piloted in 2005.

### STRIVING FOR EXCELLENCE IN OPERATIONAL SAFETY

**Safety of staff and those who work or live around EnCana's operations is of prime importance.** During 2004, EnCana's reportable injury rate fell 45 percent from 1.70 to 1.17 incidents per 200,000 hours worked, a rate that is below Canadian industry average. The company attributes this record to a collaborative engagement with its major contractors and suppliers to improve safety performance.

Tragically, five contract workers died in 2004 in separate operational accidents. Three of these deaths were associated with drilling operations and two with oilfield trucking operations. EnCana expresses its deepest sympathy to the family and friends of those workers. All of these incidents were, or are being, investigated by occupational health authorities and the company. Resulting safety lessons about preventing future occurrences of this nature are shared with EnCana staff, contractors and other industry workers.

In 2004, EnCana focused special attention on safe drilling and completions practices with a goal of further reducing incidents and improving environmentally responsible performance. Examples of new best practices include the introduction of an EnCana wellsite representative orientation program in the Fort Nelson Business Unit, and a derrick inspection program in the company's U.S. operations.

### ADDRESSING THE CONCERNS OF STAKEHOLDERS WHERE ENCANA OPERATES

EnCana has formalized its approach and practices for building relationships with external stakeholders by developing a Stakeholder Engagement Guide. The guide was rolled out to senior staff in late 2004. Corporate-wide implementation began in 2005.

*Colorado western slopes activities* During 2004, an unusual event occurred that affected area stakeholders. A natural gas seep surfaced in April 2004 that created bubbling in Divide Creek, located in the Piceance basin. EnCana moved

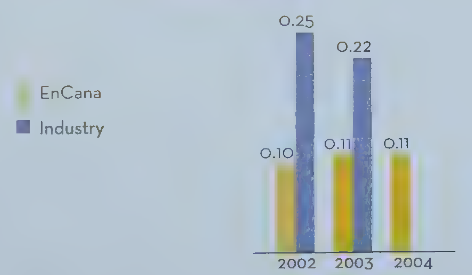
quickly to provide bottled drinking water and other assistance to nearby residents. EnCana also voluntarily ceased drilling operations within a two-mile radius of the seep and agreed to a fine of $371,200 for a faulty cement job on a well near the seep and other regulatory violations. Based on consultation with local residents and the COGCC, the majority of these funds will be applied toward a study of the underlying regional hydrogeology among other initiatives. EnCana has continued to perform extensive testing and monitoring of the seep area.

**EnCana regrets this event. The company is increasing staff complement and changing procedures to minimize the chance of reoccurrence, better understand the basin's hydrogeology, and improve communications with landowners and regulatory agencies.**

*CBM resource play engagement* EnCana's Horseshoe Canyon Coalbed Methane (CBM) resource play is Canada's first commercial CBM development. Since beginning production in 2003, the project has seen incremental expansion in the rural communities east of Calgary, Alberta. During the initial stages of development, some stakeholders expressed concerns about CBM – a relatively new and unconventional source of natural gas – particularly with respect to associated water production. EnCana hosted frequent open houses, field tours, town hall meetings, and community awareness meetings in 2004 during which it engaged local residents on its development plans. The communities learned that EnCana's Horseshoe Canyon CBM production contains virtually no associated water and is very similar to the company's shallow gas operations which have been operating in the region for decades. In response to feedback from stakeholders, EnCana implemented noise abatement systems above and beyond regulatory requirements.

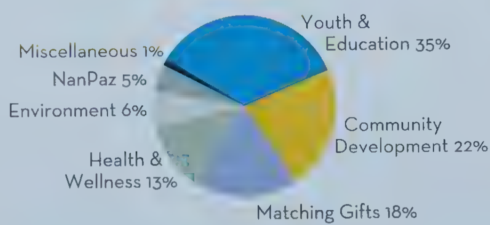
*Charting unconventional operations* During the planning stages of large-scale development programs, local stakeholders, including First Nations, area trappers, local landowners, municipal leaders and industry regulators require an understanding of the scope, size and impact of a project in a region. To help stakeholders in northeast British Columbia gain this understanding of proposed programs, EnCana and a few of its peers worked with the British Columbia Oil and Gas Commission to develop and prepare General Development Plans (GDP). This planning tool maps out the proposed multi-well programs to enable effective stakeholder input into program design and implementation. In 2004, five GDPs in the Greater Sierra area helped many stakeholders understand and provide valuable input on the drilling of close to 200 wells and the installation of approximately 400 kilometres of pipeline.

## MONITORING GHG EMISSIONS




*GHG emissions intensity from Canadian operations remained well below the 2003 industry average of 0.22, even as production increased.*

## CONTRIBUTING TO THE COMMUNITY




*EnCana contributed a total of $11.7 million in community capacity building and investment.*

## BUILDING ABORIGINAL CAPACITY

$90

*During 2004, the company continued to actively support competitive Aboriginal businesses and partnerships, spending $90 million in direct services.*

The benefits of GDPs include:

- proactive and continuing opportunities to work with First Nations and other stakeholders to incorporate their concerns;
- incorporation of First Nations traditional knowledge;
- improved planning processes;
- decreased environmental footprint as a result of a better understanding of constraints and concerns; and
- reduced timing for regulatory approval.

## Reducing Emissions Intensity

The gas and oil industry faces the challenge of reducing greenhouse gas (GHG) emissions intensity while meeting market demands for increased production. GHGs, primarily carbon dioxide ($CO_2$), are released in the course of oil and gas production and processing. EnCana is committed to reducing its emissions intensity and increasing its energy efficiency through the use of technology. The company commissioned the development of a software program, Emissions Manager, to establish a baseline and understand its emissions profile in order to identify opportunities for improvement. The software is being implemented in EnCana's Canadian and U.S. operations. EnCana is pursuing emission reduction technologies developed internally and by other industry participants, plus it is examining investment in innovations outside the oil and gas industry that reduce emissions.

Since 2000, $CO_2$ has been injected in EnCana's 50-year-old Weyburn oilfield, in southeast Saskatchewan, the site of Canada's largest $CO_2$ enhanced oil recovery business. At Weyburn, EnCana and its partners demonstrate that oil production from a mature field can be enhanced in an environmentally responsible manner by storing $CO_2$ that would otherwise be vented from a North Dakota coal gasification plant. The Weyburn oilfield has also served as the site for Phase I of the internationally acclaimed International Energy Agency GHG Weyburn $CO_2$ Monitoring and Storage Project, the world's largest in-the-field scientific study into long-term underground $CO_2$ storage. In September 2004, this collaborative, international partnership between governments, researchers and industry concluded that 99.8 percent of $CO_2$ injected in the Weyburn field will remain securely stored underground for at least 5,000 years. The Weyburn oilfield is projected to store 14 million net tonnes of $CO_2$ over the life of the enhanced oil recovery project, the equivalent of taking 3.2 million cars off the road for one year. EnCana is examining other oil fields where enhanced oil recovery using $CO_2$ injection and storage may also work.

For the third straight year, EnCana was able to increase its solution gas conservation in 2004. At 97 percent conservation, EnCana performs above the 2003 Alberta industry average of 95.4 percent.

## Protecting the Environment Through Innovation

EnCana initiated an Environmental Innovation Fund that helps finance innovative solutions to environmental issues in the energy sector. The fund is designed to invest in both external and internal projects that improve the environmental performance associated with producing or consuming energy; and advance and demonstrate innovative technologies or practices. Targeted areas include air emission reductions, water conservation, renewable energy, and energy efficiency improvements. To date, four projects have been financed. These include: a hybrid electric vehicle demonstration, a water recycling project, a drill cuttings recycling facility and a renewable energy project which will test technology that harnesses energy associated with the movement of ocean currents off the west coast of Canada.

*Managing our physical footprint* EnCana's Environmental Innovation Fund sponsored industry's first steam-assisted gravity drainage (SAGD) drilling waste processing facility, which is under construction at EnCana's SAGD operations in northeast Alberta. The facility, which separates drilling wastes so that the water and dry cuttings can be reused, will eliminate the use of remote sumps and clean-up locations and promote recycling of waste streams. Benefits include:

- a reduction of up to 50 percent, or 10,000 cubic metres per year, of fresh water use in SAGD drilling operations;
- potential 40 percent reduction of drilling waste;
- reduction of the need to clear additional forested areas for drilling waste sumps;
- lower emissions through reduced transport; and
- lower costs.

In response to local community concerns, EnCana is implementing technological innovations to reduce drilling impacts at its Mamm Creek gas field in western Colorado:

- about 95 percent of EnCana's Mamm Creek wells are directionally drilled from central pads which reduces the number of drill pads, roads and pipelines between wells;
- water recycling and pipeline systems have reduced the number of water trucks and related noise on community roads. EnCana reuses 100 percent of the water produced during drilling;
- noise has been reduced by employing power packs similar to those used in hospitals;
- by installing sound mufflers and enclosing compressors, EnCana exceeds regulatory standards for noise reduction; and
- EnCana completes wells without flaring gas.

## Sharing Innovation, Knowledge and Experience

EnCana ensures that its accomplishments, knowledge and lessons learned are shared throughout the organization. In particular, the company hosts an internal conference every two years where technological advances, innovative solutions and learnings are shared among engineers, geologists, geophysicists, technologists and other staff. In November 2004, approximately 1,500 staff attended the two-day gEnerate conference, which included presentations on EnCana's resource plays across North America and about 200 displays highlighting the technological achievements of the business units and other departments. Positive feedback from staff showed that the conference increased understanding of resource plays and provided an opportunity to share knowledge while learning new ways to tackle challenges.

## Promoting Human Rights

While governments have the primary responsibility to promote and protect human rights, EnCana supports and respects human rights within the company's sphere of influence. EnCana prepared and delivered human rights briefings to more than 440 individuals, including members of the Government of Ecuador and military participants in the area of the company's operations. At the briefings, EnCana informed participants of its position on human rights, as well as basic human rights as defined by Ecuadorian law.

EnCana has developed a security program which provides guidelines and requirements to ensure that EnCana's personnel and assets are protected while taking into account considerations for human rights practices, local laws and regulations. It provides standards for selecting and assessing security providers, and assigns responsibility to EnCana's country managers or regional presidents to ensure that appropriate training takes place.

## Making a Positive Difference in the Communities Where EnCana Operates

EnCana is focused on contributing to the strength and sustainability of the communities where it is privileged to operate. The company subscribes to the Imagine Canada program, which sets a benchmark for corporate giving at one percent of pre-tax profits, on a five-year rolling average.

**EnCana partners with its employees, community organizations and other businesses to invest in four pillars: youth and education, health and wellness, the environment, and community development.** In 2004, EnCana's prime focus was on education initiatives addressing the shortage of skilled labour in the oil and gas industry.

*Enabling communities* The Canadian Association of Petroleum Producers (CAPP) recognized EnCana with a Stewardship of Excellence Award for its socio-economic performance in Fort Nelson, B.C., where the company built a comprehensive community action plan. The plan promoted local hiring, economic development and capacity building through community investment, environmental stewardship and community empowerment.

*Making a difference together* While EnCana invested more than $11.7 million in 2004 through its Community Investment program, company employees are equally committed to the communities where they work and live. EnCana's employee charitable giving program, EnCana Cares, provides an

opportunity for staff to donate to charitable organizations of their choice through the convenience of payroll deduction. EnCana provides a dollar-for-dollar match of employees' donations during its fall campaign and through the year-round Matching Gifts program. In 2004, EnCana staff donated more than $1.5 million to a wide variety of worthy charitable causes.

EnCana employees were moved by the tragedy in South Asia arising from the earthquake and resulting tsunamis. Recognizing the profound need, the company amended its standard dollar-for-dollar matching gifts policy by double-matching all individual employee contributions, which, when complemented by the Government of Canada's dollar-for-dollar match of individual donations, translated into more than $750,000 for those organizations delivering aid to victims.

*Building aboriginal capacity* "EnCana's support to Saddle Lake First Nation in its rig deal has been the catalyst for expanded growth of Saddle Lake First Nation business development initiatives. We look forward to future opportunities with EnCana. They have been really supportive of working with all First Nations."
*– Chief Eddy Makokis, Saddle Lake First Nation*

EnCana works with approximately 70 Canadian aboriginal communities and organizations on various educational and business endeavours. In 2004, aboriginal firms and partnerships provided more than $90 million in direct services to EnCana, which included road maintenance, construction, fuel supply, security and the provision of supplies for drilling, camps and catering. Through the establishment of scholarship programs, EnCana is recruiting aboriginal youth to work in a wide variety of company assignments.

Building on EnCana's success in Alberta, where seven drilling rig partnerships have been established, a partnership was forged with the Fort Nelson First Nation, resulting in the ownership and operation of the first drilling rig by a B.C. First Nation.

EnCana was recognized by the Alberta Chamber of Resources and the Alberta Government's *Rewarding Partnerships Program* for its partnership with the Métis Nation of Alberta Association. This is a first-of-its-kind model, involving 100 percent Métis equity ownership of a drilling rig and a four-year contract for utilizing the rig.

## EnCana – Principled, Responsible and Continually Improving

The application of EnCana's Corporate Responsibility Policy continued during 2004. The information provided in this section of the annual report shows that, while EnCana has faced a number of challenges this past year, the company has achieved success in many areas with resulting improvements across the organization.

External recognition provides one means for tracking performance. In 2004, EnCana received numerous awards for its activities. A sampling of the awards related to corporate responsibility includes:

- Better Business Bureau of Southern Alberta: Ethical business practices in the large company category;
- Weyburn Chamber of Commerce: Community Involvement Award; and
- EnCana won both a World Oil award and an International Cooperation award, sponsored by the Canadian International Development Agency and Canadian Manufacturers and Exporters. These awards were for the company's work in the Integrated Community Health Initiative in Ecuador.

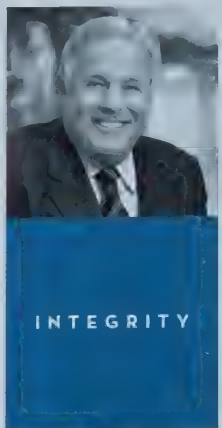
Underscoring its commitment to becoming a leader in corporate responsibility, EnCana benchmarks itself against other companies' practices, listens to and considers stakeholder advice, builds upon its lessons learned and continually looks for opportunities to improve its operations. In 2005 EnCana will continue to focus on:

- engaging stakeholders and working with local communities;
- decreasing EnCana's physical footprint, protecting natural diversity and reducing emissions intensity through innovation and best practices; and
- enhancing corporate responsibility reporting to key stakeholders.

Comments and suggestions on EnCana's corporate responsibility reporting are welcome and appreciated, and can be submitted to corporate.responsibility@encana.com. Additional information about EnCana's commitment to corporate responsibility is available at www.encana.com.

Message from EnCana's Chairman David P. O'Brien

# EFFECTIVE GOVERNANCE




In 2004, EnCana's strategy evolved through a sharpening of our focus on our competitive advantages resulting in a return to our roots in developing resource plays. We believe the future potential of EnCana lies in our vast unconventional resource asset base and our expertise in unlocking these resources. Our success over the past year indicates that we are on the right track. Last year we became the number one producer of natural gas in North America and have a leading technological and cost position in the development of in-situ oilsands. In 2004 EnCana shares delivered a 46 percent return on the New York Stock Exchange (NYSE) and a 35 percent return on the Toronto Stock Exchange (TSX).

EnCana and its Board of Directors believe there is a positive correlation between good corporate governance and strong company performance. As a result, our priority is to maintain high standards of corporate governance to help deliver shareholder value. The building of high standards of corporate governance begins with a substantial majority of independent directors who have no material relationship with the company and who can ensure the accountability of senior management. Fifteen of the Board's 16 members are independent. To execute a leading system of corporate governance, processes and practices must be assessed on a continual basis. The Board's dedication to strong corporate governance and to the evolution of operating practices is evident in the revisions and enhancements we made to our practices in 2004:

## 2004 CORPORATE GOVERNANCE HIGHLIGHTS:

*Separate Chairman and CEO roles formalized*

Shareholders approved a by-law which requires the Chairman and the Chief Executive Officer of the corporation to be different individuals. This move ensures separation of the Board from management and reflects a best practice for corporate governance.

*Business Conduct & Ethics Practice approved*

The Business Conduct & Ethics Practice, approved this year by our Board of Directors, requires review and sign-off by all officers, employees, contractors and consultants.

*Orientation and continuing education of directors*

Internal education opportunities provided to directors included a tour of company facilities in northeast British Columbia, a reserves workshop covering disclosure requirements and a technical conference focusing on resource plays.

### *Performance Share Units (PSU) grants expanded*

The PSU program, which further aligns employee compensation and shareholder returns by directly tying the value of long-term incentives to relative total shareholder return, was extended to all eligible employees. PSUs only have value if total shareholder returns, compared to a group of peer companies over a three-year period, exceed a specified level. Long-term incentive grants in 2004 were primarily in the form of PSUs.

### *Board and Committee performance assessments expanded*

The Board continued the practice of regular evaluation of the Board, its committees and its members through the use of a directors' questionnaire on Board Effectiveness and expanded the evaluation to include directors' self and peer assessments. The Chairman also met individually with each director to discuss the peer assessment and the questionnaire on Board Effectiveness.

EnCana fully complies with various rules and regulations, including Toronto Stock Exchange guidelines, the provisions of the Sarbanes-Oxley Act of 2002 and the rules adopted by the U.S. Securities and Exchange Commission pursuant to that Act. We are in compliance with New York Stock Exchange requirements in all significant respects. We are committed to the high standards of transparent reporting and accountability that these regulations represent.

As a gas and oil company, reserves are our most important asset and accordingly we conduct an external evaluation of all of our reserves every year. We employ top tier independent qualified reserves evaluation firms, whose appointment is reviewed by a Reserves Committee of the Board, to thoroughly evaluate our reserves. The Reserves Committee reviews procedures relating to the reserves evaluation process, the disclosure of reserves data and compliance with regulatory requirements, both with management and our external evaluators. It is these rigorous procedures that give me, as a shareholder, confidence in our reserve reporting . Reserves are one of the critical elements in determining financial results and value creation.


We are also proud of the recognition we have received for our business practices. EnCana received the 2004 Grand Prix Award for Best Overall Investor Relations in the Mega-cap category, from IR Magazine, which recognizes the timeliness and effectiveness of our ongoing communication with shareholders and procedures to facilitate shareholder feedback.

We also received an award from the southern Alberta chapter of the Better Business Bureau for our ethical business practices in the large company category. The award was based on our overall community involvement, environmental programs, and corporate policies and practices.

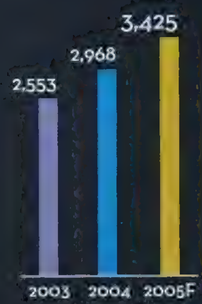
I would like to take this opportunity to thank Dick Haskayne, who is not standing for re-election, for his participation on the Board. Dick has served on the Board for 12 years and has made a major contribution to the success of EnCana since the merger and of Alberta Energy Company Ltd. in the years prior to the merger. In particular, he played a very important role as Chairman of the Human Resources and Compensation Committee.

We have had another successful year characterized with strong results and outstanding operating achievements. I would like to thank the Board, management team and employees for their tremendous efforts and commitment to delivering shareholder value.

On behalf of the Board of Directors,

DAVID P. O'BRIEN
*Chairman*

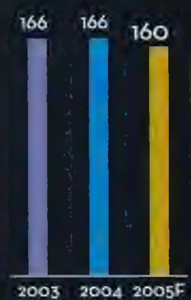
# UNCONVENTIONAL SALES




**TOTAL NORTH AMERICAN NATURAL GAS SALES**
*(MMcf/d)*

*In 2005, North American natural gas sales are forecast to grow by 15 percent using the midpoint of the guidance.*

## NATURAL GAS




**TOTAL NORTH AMERICAN OIL AND NGLS SALES**
*(Mbbls/d)*

*Divestiture of conventional oil assets in 2005 will be offset by growing sales from the oilsands.*

## OIL & NGLS

# ADVISORIES

## FORWARD-LOOKING STATEMENTS

In the interest of providing EnCana shareholders and potential investors with information regarding the Company and its subsidiaries, including management's assessment of EnCana's and its subsidiaries' future plans and operations, certain statements contained in this Annual Report constitute forward-looking statements within the meaning of the "safe harbour" provisions of the United States Private Securities Litigation Reform Act of 1995. Forward-looking statements are typically identified by words such as "anticipate", "believe", "expect", "plan", "intend", "forecast", "target", "project" or similar words suggesting future outcomes or statements regarding an outlook. Forward-looking statements in this Annual Report include, but are not limited to, statements with respect to: the Company's ability to deliver predictable and profitable production growth in the future; production and sales estimates for produced gas, crude oil and NGLs for 2005 and beyond; projections relating to the potential for sustained internal per share sales growth over the next five years and beyond and the assumptions relating thereto; the projected future sources of North American gas and oil supplies and the timing and materiality of existing and potential future external supply sources; the sources of the Company's future competition; projections relating to the ability to replicate the Company's land position in the future; divestitures which may occur in 2005 and beyond, including the planned divestiture of Ecuador, Gulf of Mexico and other non-core assets, and projections relating to potential proceeds therefrom, and the use of proceeds therefrom, including share purchases under the Company's Normal Course Issuer Bid and repayment of debt; projections relating to the Company's production profile and product mix after planned divestitures; projections relating to net asset value per share growth in the future; projections relating to proved reserves, reserve life index and resource potential, including drilling plans and the potential conversion of resource potential into proved reserves over the next five years and beyond, including for the Company and its subsidiaries taken as a whole, and in relation to various individual projects, regions and initiatives including without limitation Greater Sierra, Cutbank Ridge, coalbed methane, shallow gas, Jonah, Piceance, Fort Worth, East Texas, Foster Creek and Pelican Lake; projections relating to the impact of waterflooding and CO2 injections on various projects; projections relating to anticipated or pending regulatory approvals for various projects and initiatives; plans and projections relating to potential refining opportunities and the impact thereof on market access for and the value of the Company's heavy oil projects and production; the ability of resource plays to generate profitable production and sales growth and reserve growth in the future, including the ability to offset annual production declines; projections relating to resource play geologic risk, well decline rates, per-well capital costs, operating costs and reserve recoveries, and the reliability and predictability thereof; projections relating to potential reserves and production available in connection with the Company's SAGD operations, including production levels for 2005, 2006 and long term production potential; projections relating to rates of return, including risk-adjusted after-tax project returns, cost of capital returns and weighted rates of return at various commodity price levels; projections regarding North American supply, demand and storage requirements and the projected future benefits from the Company's storage assets; projections relating to the Company's sources of production, decline rates and production growth per share in five years and long-term potential for additional value creation; the Company's plans to focus on growing natural gas production and storage capacity in North America and medium and long-term growth prospects internationally; projections relating to future oil, natural gas and NGLs prices and price volatility in 2005 and beyond, and the reasons therefor; amounts which may be issued under the Company's multi-jurisdictional shelf prospectus program; the Company's projected capital investment levels for 2005 and beyond, the anticipated allocation thereof and the source of funding therefor; the effect of the Company's risk management program, including the impact of derivative financial instruments; the Company's execution of share purchases under its Normal Course Issuer Bid, including the number of shares which may be purchased thereunder; projections relating to the Company's defence of lawsuits; projections and assumptions relating to capital expenditures, operating costs, sales volumes, tax rates, interest rates, foreign currency exchange rates, inflation rates and other variables impacting the Company and its operations; projections relating to expenses under the Company's Performance Share Units plan; anticipated asset retirement obligation expenses; the impact of the Kyoto Accord on operating costs; projected tax rates and projected current taxes payable for 2005 and the adequacy of the Company's provision for taxes; rating agency monitoring and reviews which may occur in the future; and the projected impact of off-balance sheet arrangements.

Readers are cautioned not to place undue reliance on forward-looking statements, as there can be no assurance that the plans, intentions or expectations upon which they are based will occur. By their nature, forward-looking statements involve numerous assumptions, known and unknown risks and uncertainties, both general and specific, that contribute to the possibility that the predictions, forecasts, projections and other forward-looking statements will not occur, which may cause the Company's actual performance and financial results in future periods to differ materially from any estimates or projections of future performance or results expressed or implied by such forward-looking statements. These risks and uncertainties include, among other things: volatility of oil and gas prices; fluctuations in currency and interest rates; product supply and demand; market competition; risks inherent in the Company's and its subsidiaries' marketing operations, including credit risks; imprecision of reserve estimates and estimates of recoverable quantities of oil, natural gas and liquids from resource plays and other sources not currently classified as proved; the Company's and its subsidiaries' ability to replace and expand oil and gas reserves; its ability to generate sufficient cash flow from operations to meet its current and future obligations; the Company's ability to access external sources of debt and equity capital; the timing and the costs of well and pipeline construction; the Company's and its subsidiaries' ability to secure adequate product transportation; changes in environmental and other regulations or the interpretations of such regulations; political and economic conditions in the countries in which the Company and its subsidiaries operate, including Ecuador; the risk of international war, hostilities, civil insurrection and instability affecting countries in which the Company and its subsidiaries operate and terrorist threats; risks associated with existing and potential future lawsuits and regulatory actions made against the Company and its subsidiaries; and other risks and uncertainties described from time to time in the reports and filings made with securities regulatory authorities by EnCana. Statements relating to "reserves" or "resources" or "resource potential" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and

assumptions that the resources and reserves described exist in the quantities predicted or estimated, and can be profitably produced in the future. Although EnCana believes that the expectations represented by such forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. Readers are cautioned that the foregoing list of important factors is not exhaustive. Furthermore, the forward-looking statements contained in this Annual Report are made as of the date of this Annual Report, and EnCana does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained in this Annual Report are expressly qualified by this cautionary statement.

## OIL AND GAS INFORMATION

EnCana's disclosure of reserves data and other oil and gas information is made in reliance on an exemption granted to EnCana by Canadian securities regulatory authorities which permits it to provide such disclosure in accordance with U.S. disclosure requirements. The information provided by EnCana may differ from the corresponding information prepared in accordance with Canadian disclosure standards under National Instrument 51-101 ("NI 51-101"). The reserves quantities disclosed by EnCana represent net proved reserves calculated using the standards contained in Regulation S-X of the U.S. Securities and Exchange Commission. Further information about the differences between the U.S. requirements and the NI 51-101 requirements is set forth under the heading "Note Regarding Reserves Data and Other Oil and Gas Information" in EnCana's Annual Information Form.

### CRUDE OIL, NATURAL GAS LIQUIDS AND NATURAL GAS CONVERSIONS

In this Annual Report, certain crude oil and natural gas liquids ("NGLs") volumes have been converted to millions of cubic feet equivalent ("MMcfe") or thousands of cubic feet equivalent ("Mcfe") on the basis of one barrel ("bbl") to six thousand cubic feet ("Mcf"). Also, certain natural gas volumes have been converted to barrels of oil equivalent ("BOE"), thousands of BOE ("MBOE") or millions of BOE ("MMBOE") on the same basis. MMcfe, Mcfe, BOE, MBOE and MMBOE may be misleading, particularly if used in isolation. A conversion ratio of one bbl to six Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not necessarily represent value equivalency at the well head.

### RESOURCE PLAY, ESTIMATED ULTIMATE RECOVERY AND RESOURCE POTENTIAL

EnCana uses the terms resource play, estimated ultimate recovery and resource potential. Resource play is a term used by EnCana to describe an accumulation of hydrocarbons known to exist over a large areal expanse and/or thick vertical section, which when compared to a conventional play, typically has a lower geological and/or commercial development risk and lower average decline rate. As used by EnCana, estimated ultimate recovery has the meaning set out jointly by the Society of Petroleum Engineers and World Petroleum Congress in the year 2000, being those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from an accumulation, plus those quantities already produced therefrom. Resource potential is a term used by EnCana to refer to the estimated quantities of hydrocarbons that may be added to proved reserves over a specified period of time largely from a specified resource play or plays. EnCana's current stated estimates of unbooked resource potential utilize a five year time frame for their specified period of time.

## CURRENCY, NON-GAAP MEASURES AND ADDITIONAL INFORMATION

### CURRENCY

All information included in this Annual Report and the Consolidated Financial Statements and comparative information is shown on a U.S. dollar, after-royalties basis unless otherwise noted. Sales forecasts reflect the mid-point of current public guidance on an after royalties basis. Current Corporate Guidance assumes a U.S. dollar exchange rate of $0.79 for every Canadian dollar.

### NON-GAAP MEASURES

Certain measures in this Annual Report do not have any standardized meaning as prescribed by Canadian generally accepted accounting principles ("Canadian GAAP") such as Cash Flow from Continuing Operations, Cash Flow, Cash Flow from Continuing Operations per share – basic, Cash Flow from Continuing Operations per share – diluted, Cash Flow per share – basic and Cash Flow per share – diluted, Operating Earnings and Operating Earnings per share – diluted, Operating Earnings from Continuing Operations and Operating Earnings from Continuing Operations per share – diluted and therefore are considered non-GAAP measures. Therefore, these measures may not be comparable to similar measures presented by other issuers. These measures have been described and presented in this Annual Report in order to provide shareholders and potential investors with additional information regarding the Company's liquidity and its ability to generate funds to finance its operations. Management's use of these measures has been disclosed further in this Annual Report as these measures are discussed and presented.

### ADDITIONAL INFORMATION

Further information regarding EnCana Corporation can be accessed under the Company's public filings found at www.sedar.com and on the Company's Web site at www.encana.com.

## DIFFERENCES IN ENCANA'S CORPORATE GOVERNANCE PRACTICES COMPARED TO NYSE CORPORATE GOVERNANCE STANDARDS

As a Canadian company listed on the New York Stock Exchange ("NYSE"), EnCana is not required to comply with most of the NYSE Corporate Governance Listing Standards and instead may comply with Canadian Corporate Governance Practices. EnCana is, however, required to disclose the significant differences between its corporate governance practices and the NYSE corporate governance standards. A summary of the significant differences between EnCana's corporate governance practices and those contained in the NYSE rules is available on EnCana's Web site (www.encana.com). Except as described in this summary, EnCana is in compliance with the NYSE corporate governance standards in all significant respects.

# ECA FINANCIALS 04

## MANAGEMENT'S DISCUSSION AND ANALYSIS



## FINANCIALS

ENCANA

# MANAGEMENT'S DISCUSSION AND ANALYSIS

*This Management's Discussion and Analysis ("MD&A") for EnCana Corporation ("EnCana" or the "Company") should be read in conjunction with the audited Consolidated Financial Statements ("Consolidated Financial Statements") for the year ended December 31, 2004, as well as the audited Consolidated Financial Statements and MD&A for the year ended December 31, 2003. Readers are referred to the legal advisory detailing "Forward-Looking Statements" found on page 47. Certain terms used in this MD&A (and not otherwise defined) are defined in the notes regarding Oil and Gas Information and Currency, Non-GAAP Measures and Additional Information, found on page 48. The Consolidated Financial Statements and comparative information have been prepared in accordance with Canadian GAAP in United States dollars (except where indicated as being in another currency).*

*This MD&A has been prepared in United States dollars with production and sales volumes presented on an after royalties basis consistent with United States protocol reporting. This MD&A is dated February 22, 2005.*

## SUMMARY OF KEY EVENTS AND FINANCIAL RESULTS IN 2004

- Total sales volumes increased 16 percent to 4,560 million cubic feet of gas ("MMcf") equivalent per day ("MMcfe/d") comprised of 2,998 MMcf/d of natural gas and 260,383 barrels per day ("bbls/d") of liquids.
- Average sales prices, excluding financial hedges, increased 12 percent for North American natural gas and 27 percent for North American liquids.
- EnCana recorded realized commodity and currency hedging losses of approximately $0.7 billion after tax.
- EnCana purchased approximately 20 million shares under the Normal Course Issuer Bid for a total cost of $1 billion.
- As part of the sharpening of EnCana's strategic focus to unconventional resource plays, the Company:
    - Acquired Tom Brown, Inc. ("TBI") on May 19, 2004 for approximately $2.7 billion, contributing approximately 194 MMcfe/d to EnCana's annual production;
    - Sold its United Kingdom ("U.K.") operations for approximately $2.1 billion on December 1, 2004;
    - Completed approximately $1.4 billion in mature, North American conventional property dispositions during 2004; and
    - Initiated a strategic review of its Ecuador assets and has announced that these assets are for sale.

## OVERVIEW

EnCana is a leading independent North American oil and gas company. EnCana pursues predictable, profitable growth from its portfolio of long-life resource plays situated in Canada and the United States. EnCana's disciplined pursuit of these unconventional resources has enabled it to become North America's leading natural gas producer and a technical and cost performance leader in the development of oilsands through in-situ recovery.

EnCana reports the results of its continuing operations under two business segments:

- Upstream, which focuses on the Company's exploration for and development and production of natural gas, crude oil and natural gas liquids ("NGLs"), and other related activities.
- Midstream & Market Optimization, which is conducted by the Midstream & Marketing division. Midstream focuses on natural gas storage operations, NGLs processing and power generation operations. Marketing undertakes market optimization activities to enhance the sale of Upstream's proprietary production. Market optimization results reflect third party purchases and sales of product which provide operational flexibility for transportation commitments, product type, delivery points and customer diversification.

## BUSINESS ENVIRONMENT

### NATURAL GAS

Lack of overall North American industry natural gas supply combined with increasing demand and the influence of high crude oil prices have continued to result in historically high average NYMEX gas prices. Higher average AECO gas prices in 2004 can be attributed to an increased NYMEX index partially offset by wider AECO differentials from NYMEX combined with the appreciation of the U.S./Canadian dollar exchange rate. The increased AECO/NYMEX basis differential in 2004 compared to 2003 can be attributed to increased transportation differentials for the incremental sales volumes transported from Alberta to Eastern Canada.

| ***Natural Gas Price Benchmarks*** *(average for the period)* | 2004 | 2004 vs 2003 | 2003 | 2003 vs 2002 | 2002 |
|---|---|---|---|---|---|
| AECO Price *(C$/Mcf)* | $ 6.79 | 1% | $ 6.70 | 65% | $ 4.07 |
| NYMEX Price *($/MMBtu)* | 6.14 | 14% | 5.39 | 67% | 3.22 |
| Rockies (Opal) Price *($/MMBtu)* | 5.23 | 27% | 4.12 | 103% | 2.03 |
| AECO/NYMEX Basis Differential *($/MMBtu)* | 0.91 | 40% | 0.65 | -2% | 0.66 |
| Rockies/NYMEX Basis Differential *($/MMBtu)* | 0.91 | -28% | 1.27 | 7% | 1.19 |

### CRUDE OIL

The West Texas Intermediate ("WTI") crude oil price was significantly higher both in the fourth quarter and for the year of 2004 compared to the corresponding periods in 2003. This was caused by continued world oil demand strength, primarily in Asia and North America, and during the fourth quarter, concerns over winter heating oil supplies in North America. The world oil price in the fourth quarter was further supported by supply uncertainties in the Middle East and West Africa, as well as reduced supply from the Gulf of Mexico, the North Sea, Russia and Canada. OPEC's reaction to high prices resulted in an increase in production over the course of the year. However, the incremental production was a heavier and more sour blend of crude oil than WTI and put added pressure on light to heavy oil price differentials.

The WTI/Bow River heavy oil differential widened in the fourth quarter of 2004 to record levels primarily due to the higher price for WTI, as well as wider U.S. Gulf Coast light to heavy product differentials and increased Canadian heavy crude-on-crude competition. As a percentage of WTI, Bow River Blend average sales price for the fourth quarter of 2004 was 60 percent of WTI compared to 69 percent in the fourth quarter of 2003.

On a year over year basis, the WTI/Bow River heavy oil differential was higher primarily as a result of the increase in WTI. NAPO blend in Ecuador is a heavier crude than the SOTE Oriente blend (previously the predominant crude oil from Ecuador) resulting in a wider differential to WTI. The fourth quarter and annual 2004 increases in the WTI/Oriente differential compared to the same periods in 2003 are primarily related to the increase in the WTI price as well as wider U.S. Gulf Coast light to heavy product differentials.

| *Crude Oil Price Benchmarks* *(average for the period, unless otherwise noted)* | 2004 | 2004 vs 2003 | 2003 | 2003 vs 2002 | 2002 |
|---|---|---|---|---|---|
| WTI ($/bbl) | $ 41.47 | 34% | $ 30.99 | 19% | $ 26.15 |
| Dated Brent ($/bbl) | 38.27 | 33% | 28.83 | 15% | 25.02 |
| WTI/Bow River Differential ($/bbl) | 12.82 | 60% | 8.01 | 35% | 5.93 |
| WTI/OCP NAPO Differential (Ecuador) ($/bbl) (1) | 14.33 | 78% | 8.06 | – | – |
| WTI/Oriente Differential (Ecuador) ($/bbl) | 11.12 | 99% | 5.59 | 34% | 4.16 |

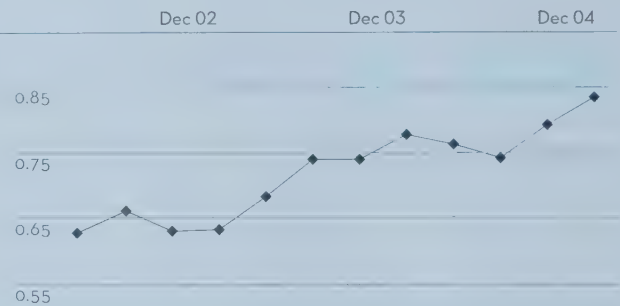
*(1) The WTI/OCP NAPO Differential was posted as of September 2003.*

### U.S./Canadian Dollar Exchange Rates

The 2004 year-end U.S./Canadian dollar exchange rate of US$0.831 per C$1 increased by seven percent compared with the 2003 year-end rate of $0.774. The 2003 year-end rate increased by 22 percent when compared with the 2002 year-end rate of $0.633.

The increased value of the Canadian dollar has resulted primarily from continuing differences between Canadian and U.S. interest rates and the U.S. current account deficit.

*U.S./Canadian Dollar Period End Exchange Rates*




## Consolidated Financial Results

### Summary

#### 2004 vs. 2003

Cash flow increased to $5.0 billion from $4.5 billion, an increase of $0.5 billion or $1.34 per share diluted. Higher commodity prices and growth in sales volumes were partially offset by realized financial commodity and currency hedge losses and increased expenses. Cash flow from continuing operations also increased $0.5 billion, or $1.22 per share diluted, to a total of $4.6 billion in 2004 compared to $4.1 billion in 2003.

Net earnings increased $1.1 billion to $3.5 billion in 2004. Included in net earnings is a $1.4 billion gain on the sale of U.K. discontinued operations. EnCana's net earnings from continuing operations in 2004 are $2.2 billion compared with $2.1 billion in 2003. Higher volumes and prices in 2004 were offset by increased expenses and increased depreciation, depletion and amortization ("DD&A"). Net earnings in 2004 include an unrealized after tax gain of $229 million on Canadian issued U.S. denominated debt resulting from the increase in the value of the Canadian dollar and an unrealized after tax mark-to-market accounting loss of $165 million.

#### 2003 vs. 2002

Cash flow increased 84 percent and net earnings increased 191 percent compared with 2002 as a result of growth in sales volumes, higher commodity prices and the inclusion of a full year of post merger operations, partially offset by increased expenses.

Net earnings for the year also included an unrealized after-tax gain on the U.S. denominated debt issued in Canada of $433 million, or $0.90 per share diluted resulting from the increase in the value of the Canadian dollar versus the U.S. dollar, and a $359 million, or $0.75 per share diluted recovery of future income taxes resulting from reductions in the Canadian federal and Alberta corporate income tax rates.

Cash flow from continuing operations and net earnings from continuing operations increased 101 percent and 222 percent, respectively, compared to 2002.

## ACQUISITIONS AND DIVESTITURES

In May 2004, the Company successfully completed its cash tender offer for all of the outstanding common shares of TBI which became an indirect wholly owned subsidiary following the merger of TBI and another of the Company's indirect wholly owned subsidiaries. The total consideration was approximately $2.3 billion plus the assumed debt of TBI of approximately $0.4 billion. The TBI assets are primarily strong growth long-life North American resource play assets, contributing approximately 194 MMcfe/d (32,300 BOE/d) to EnCana's annual production in 2004, which complement existing Company assets and are consistent with management's strategic focus.

In December 2004, a subsidiary of the Company sold its U.K. operations for approximately $2.1 billion. These assets included interests in the Buzzard, Scott and Telford oil fields, plus interests in other satellite discoveries and exploration licences in the U.K. central North Sea. In the first quarter of 2004, an EnCana subsidiary completed the purchase, through two separate transactions, of additional interests in the North Sea, for net cash consideration of approximately $131 million.

In line with the Company's strategy of focusing on its inventory of North American resource play assets in 2004, the Company disposed of a number of mature conventional producing assets. The Company recorded proceeds of approximately $1.1 billion on the sales of conventional oil and natural gas assets which were primarily located in western Canada. At the time of disposition, these assets were producing approximately 200 MMcfe/d (33,770 BOE/d).

In February 2004, the Company sold its 53.3 percent partnership interest in Petrovera Resources ("Petrovera") for net cash consideration of approximately $287 million including working capital adjustments. Petrovera's production was approximately 120 MMcfe/d (20,000 BOE/d) of primarily heavy crude oil at the time of disposition.

In December 2004, the Company sold its interest in the Alberta Ethane Gathering System for approximately $108 million.

Proceeds received from the non-core divestitures described above have been used to repay debt, purchase EnCana shares and for general corporate purposes.

| ***Consolidated Financial Summary*** *($ millions, except per share amounts)* | 2004 | 2004 vs 2003 | 2003 | 2003 vs 2002 | 2002 |
|---|---|---|---|---|---|
| Cash Flow (1) | $ 4,980 | 12% | $ 4,459 | 84% | $ 2,419 |
| – per share – basic | 10.82 | 15% | 9.41 | 63% | 5.79 |
| – per share – diluted | 10.64 | 14% | 9.30 | 63% | 5.72 |
| Net Earnings | 3,513 | 49% | 2,360 | 191% | 812 |
| – per share – basic | 7.63 | 53% | 4.98 | 157% | 1.94 |
| – per share – diluted | 7.51 | 53% | 4.92 | 156% | 1.92 |
| Operating Earnings (2) | 1,976 | 41% | 1,399 | 78% | 787 |
| – per share – diluted | 4.22 | 45% | 2.92 | 57% | 1.86 |
| Cash Flow from Continuing Operations (1) | 4,605 | 11% | 4,135 | 101% | 2,059 |
| – per share – basic | 10.00 | 15% | 8.72 | 77% | 4.93 |
| – per share – diluted | 9.84 | 14% | 8.62 | 77% | 4.87 |
| Net Earnings from Continuing Operations | 2,211 | 3% | 2,142 | 222% | 666 |
| – per share – basic | 4.80 | 6% | 4.52 | 184% | 1.59 |
| – per share – diluted | 4.72 | 6% | 4.47 | 183% | 1.58 |
| Operating Earnings from Continuing Operations (2) | 1,989 | 47% | 1,350 | 115% | 629 |
| – per share – diluted | 4.25 | 51% | 2.82 | 89% | 1.49 |
| Revenues, Net of Royalties | 11,810 | 22% | 9,686 | 63% | 5,928 |
| Total Assets | 31,213 | 29% | 24,110 | 21% | 19,912 |
| Long-Term Debt | 7,742 | 27% | 6,088 | 21% | 5,051 |
| Cash Dividends (3) | 183 | 32% | 139 | 29% | 108 |

*(1) Cash Flow and Cash Flow from Continuing Operations are non-GAAP measures and are discussed under "Cash Flow" in this MD&A.*
*(2) Operating Earnings and Operating Earnings from Continuing Operations are non-GAAP measures and are described and discussed under "Operating Earnings" in this MD&A.*
*(3) Represents cash dividends paid to common shareholders at the rate of US$0.40 per share annually except for 2003 and 2002 which were paid at the rate of C$0.40 per share annually.*

| *Quarterly Summary* *($ millions, except per share amounts)* | 2004 | | | | 2003 | | | |
|---|---|---|---|---|---|---|---|---|
| | Q4 | Q3 | Q2 | Q1 | Q4 | Q3 | Q2 | Q1 |
| Cash Flow (1) | $ 1,491 | $ 1,363 | $ 1,131 | $ 995 | $ 1,254 | $ 977 | $ 1,007 | $ 1,221 |
| – per share – basic | 3.25 | 2.95 | 2.46 | 2.16 | 2.71 | 2.06 | 2.10 | 2.54 |
| – per share – diluted | 3.21 | 2.92 | 2.43 | 2.13 | 2.69 | 2.04 | 2.08 | 2.52 |
| Net Earnings | 2,580 | 393 | 250 | 290 | 426 | 290 | 807 | 837 |
| – per share – basic | 5.62 | 0.85 | 0.54 | 0.63 | 0.92 | 0.61 | 1.68 | 1.74 |
| – per share – diluted | 5.55 | 0.84 | 0.54 | 0.62 | 0.91 | 0.61 | 1.67 | 1.73 |
| Operating Earnings (2) | 573 | 559 | 379 | 465 | 316 | 278 | 277 | 528 |
| – per share – diluted | 1.23 | 1.20 | 0.81 | 1.00 | 0.68 | 0.58 | 0.57 | 1.09 |
| Cash Flow from Continuing Operations (1) | 1,429 | 1,259 | 1,021 | 896 | 1,103 | 918 | 990 | 1,124 |
| – per share – basic | 3.11 | 2.73 | 2.22 | 1.94 | 2.39 | 1.94 | 2.06 | 2.34 |
| – per share – diluted | 3.07 | 2.70 | 2.19 | 1.92 | 2.37 | 1.92 | 2.04 | 2.32 |
| Net Earnings from Continuing Operations | 1,188 | 432 | 265 | 326 | 447 | 266 | 801 | 628 |
| – per share – basic | 2.59 | 0.94 | 0.58 | 0.71 | 0.97 | 0.56 | 1.67 | 1.31 |
| – per share – diluted | 2.56 | 0.93 | 0.57 | 0.70 | 0.96 | 0.56 | 1.65 | 1.30 |
| Operating Earnings from Continuing Operations (2) | 612 | 553 | 362 | 462 | 337 | 254 | 271 | 488 |
| – per share – diluted | 1.32 | 1.19 | 0.78 | 0.99 | 0.72 | 0.53 | 0.56 | 1.01 |
| Revenues, Net of Royalties | 4,208 | 2,320 | 2,552 | 2,730 | 2,639 | 2,190 | 2,233 | 2,624 |

*(1) Cash Flow and Cash Flow from Continuing Operations are non-GAAP measures and are discussed under "Cash Flow" in this MD&A.*
*(2) Operating Earnings and Operating Earnings from Continuing Operations are non-GAAP measures and are described and discussed under "Operating Earnings" in this MD&A.*

## Cash Flow

EnCana's cash flow increased to $4,980 million in 2004, an increase of $521 million from 2003. This increase reflects the Company's overall 16 percent sales volume growth, increased prices in 2004, realized hedge losses, realized foreign exchange gains and an increase in the current income tax provision. EnCana's discontinued operations contributed $375 million to cash flow in 2004, an increase of $51 million from 2003.

EnCana's 2004 cash flow from continuing operations increased $470 million, or $1.22 per share diluted, to $4,605 million over 2003 with significant items as follows:

- Natural gas sales volumes increased 16 percent to 2,968 MMcf/d.
- Average North American natural gas prices, excluding financial hedges, were $5.47 per Mcf in 2004 compared to $4.87 per Mcf in 2003, an increase of 12 percent.
- Average North American liquids prices, excluding financial hedges, were $28.77 per bbl in 2004 compared to $22.72 per bbl in 2003, an increase of 27 percent.
- Realized financial commodity and currency hedge losses included in cash flow from continuing operations were approximately $686 million ($464 million after-tax) in 2004 compared to $259 million ($164 million after-tax) for 2003.
- Realized foreign exchange gains of $190 million ($154 million after-tax) on the settlement of long-term debt in 2004 compared to realized gains of $86 million ($68 million after-tax) in 2003, as a result of the rise in the U.S./Canadian dollar exchange rate and its impact on the settlement of Canadian issued U.S. denominated debt.
- Current income tax provision increased by $680 million to $567 million in 2004 from a recovery of $113 million in 2003 partially offsetting increased cash flow from higher volumes and prices.

Cash flow measures are considered non-GAAP but are commonly used in the oil and gas industry to assist management and investors to measure the Company's ability to finance its capital programs and meet its credit obligations. The calculation of cash flow is disclosed on the Consolidated Statement of Cash Flows in the Consolidated Financial Statements.

## Net Earnings

EnCana's net earnings increased $1,153 million to $3,513 million in 2004. Included in 2004 net earnings is a gain of $1,364 million on the sale of EnCana's U.K. operations.

EnCana's net earnings from continuing operations increased $69 million, or $0.25 per share diluted in 2004 compared with 2003. In addition to the items affecting cash flow as detailed previously, significant items are:

- Unrealized mark-to-market losses of $190 million ($116 million after-tax) are included in 2004 with no corresponding amount in 2003.
- Included in 2004 is a gain due to a change in tax rates of $109 million, compared to a gain of $359 million in 2003.
- A $285 million ($229 million after-tax) unrealized gain on Canadian issued U.S. dollar debt in 2004 compared to an unrealized gain of $545 million ($433 million after-tax) in 2003. This results from the continued strengthening in the year-end U.S./Canadian dollar exchange rate between December 31, 2003 and December 31, 2004 compared to the change between December 31, 2002 and December 31, 2003.

The impacts on results from the conversion of Canadian to U.S. dollars should be considered when analyzing specific components contained in the Consolidated Financial Statements. For every 100 Canadian dollars spent on capital projects, operating expenses and administrative expenses, the Company incurred additional costs of approximately US$5.20 based on the increase in the average U.S./Canadian dollar exchange rate from $0.716 in 2003 to $0.768 in 2004. Revenues were relatively unaffected by the increase in the exchange rate since commodity prices received are largely based in U.S. dollars or in Canadian dollar prices which are closely tied to the value of the U.S. dollar.

***Reconciliation of Net Earnings from Continuing Operations from 2003 to 2004***
*($ millions)*

| | |
|---|---|
| 2003 Net Earnings from Continuing Operations | $ 2,142 |
| Upstream prices | 915 (1) |
| Upstream volumes | 864 |
| Gain on disposition of investments | 112 |
| Realized foreign exchange gain on long-term debt | 79 |
| Unrealized fair value adjustment on financial contracts | (190) |
| Unrealized foreign exchange gain on long-term debt | (260) |
| Income tax | (294) |
| Upstream expenses | (344) |
| DD&A costs | (413) |
| Realized loss on financial contracts | (427) |
| Other | 27 |
| 2004 Net Earnings from Continuing Operations | $ 2,211 |

*(1) Excludes the effect of Upstream financial hedging.*

## OPERATING EARNINGS

Operating Earnings and Operating Earnings from Continuing Operations are non-GAAP measures that show net earnings excluding non-operating items such as the after-tax gain or loss from the disposition of discontinued operations, the after-tax effects of unrealized mark-to-market accounting for derivative instruments, the after-tax gain or loss on translation of U.S. dollar denominated debt issued in Canada and the effect of the reduction in income tax rates. Management believes these items reduce the comparability of the Company's underlying financial performance between periods. The majority of the unrealized gains/losses that relate to U.S. dollar debt issued in Canada are for debt with maturity dates in excess of five years. The following table has been prepared in order to provide shareholders and potential investors with information that is more comparable between years.

| ***Summary of Operating Earnings*** *($ millions)* | 2004 | 2004 vs 2003 | 2003 | 2003 vs 2002 | 2002 |
|---|---|---|---|---|---|
| Net Earnings, as reported | $ 3,513 | 49% | $ 2,360 | 191% | $ 812 |
| Deduct: (Gain) loss on discontinuance | (1,364) | | (169) | | 12 |
| Add: Unrealized mark-to-market accounting loss (after-tax) (2) | 165 | | – | | – |
| Deduct: Unrealized foreign exchange gain on translation of Canadian issued U.S. dollar debt (after-tax) | (229) | | (433) | | (17) |
| Deduct: Future tax recovery due to tax rate reductions | (109) | | (359) | | (20) |
| Operating Earnings (1)(3) | $ 1,976 | 41% | $ 1,399 | 78% | $ 787 |

| *Summary of Operating Earnings* (continued) (*$ per Common Share – Diluted*) | 2004 | 2004 vs 2003 | 2003 | 2003 vs 2002 | 2002 |
|---|---|---|---|---|---|
| Net Earnings, as reported | $ 7.51 | 53% | $ 4.92 | 156% | $ 1.92 |
| Deduct: (Gain) loss on discontinuance | (2.92) | | (0.35) | | 0.03 |
| Add: Unrealized mark-to-market accounting loss (after-tax) [2] | 0.35 | | – | | – |
| Deduct: Unrealized foreign exchange gain on translation of Canadian issued U.S. dollar debt (after-tax) | (0.49) | | (0.90) | | (0.04) |
| Deduct: Future tax recovery due to tax rate reductions | (0.23) | | (0.75) | | (0.05) |
| Operating Earnings [1][3] | $ 4.22 | 45% | $ 2.92 | 57% | $ 1.86 |

*(1) Operating Earnings is a non-GAAP measure that shows net earnings excluding the after-tax gain or loss from the disposition of discontinued operations, the after-tax effects of unrealized mark-to-market accounting for derivative instruments, the after-tax gain on translation of U.S. dollar denominated debt issued in Canada and the effect of the reduction in income tax rates.*

*(2) The Company adopted mark-to-market accounting on derivative financial instruments prospectively on January 1, 2004. See Note 2 to the Consolidated Financial Statements.*

*(3) Unrealized (gains)/losses have no impact on cash flow.*

| *Summary of Operating Earnings from Continuing Operations* (*$ millions*) | 2004 | 2004 vs 2003 | 2003 | 2003 vs 2002 | 2002 |
|---|---|---|---|---|---|
| Net Earnings from Continuing Operations, as reported | $ 2,211 | 3% | $ 2,142 | 222% | $ 666 |
| Add: Unrealized mark-to-market accounting loss (after-tax) [2] | 116 | | – | | – |
| Deduct: Unrealized foreign exchange gain on translation of Canadian issued U.S. dollar debt (after-tax) | (229) | | (433) | | (17) |
| Deduct: Future tax recovery due to tax rate reductions | (109) | | (359) | | (20) |
| Operating Earnings from Continuing Operations [1][3] | $ 1,989 | 47% | $ 1,350 | 115% | $ 629 |
| *($ per Common Share – Diluted)* | | | | | |
| Net Earnings from Continuing Operations, as reported | $ 4.72 | 6% | $ 4.47 | 183% | $ 1.58 |
| Add: Unrealized mark-to-market accounting loss (after-tax) [2] | 0.25 | | – | | – |
| Deduct: Unrealized foreign exchange gain on translation of Canadian issued U.S. dollar debt (after-tax) | (0.49) | | (0.90) | | (0.04) |
| Deduct: Future tax recovery due to tax rate reductions | (0.23) | | (0.75) | | (0.05) |
| Operating Earnings from Continuing Operations [1][3] | $ 4.25 | 51% | $ 2.82 | 89% | $ 1.49 |

*(1) Operating Earnings from Continuing Operations is a non-GAAP measure that shows net earnings from continuing operations excluding the after-tax effects of unrealized mark-to-market accounting for derivative instruments, the gain on translation of U.S. dollar denominated debt issued in Canada and the effect of the reduction in income tax rates.*

*(2) The Company adopted mark-to-market accounting on derivative financial instruments prospectively on January 1, 2004. See Note 2 to the Consolidated Financial Statements.*

*(3) Unrealized (gains)/losses have no impact on cash flow.*

## RESULTS OF OPERATIONS

### Upstream Operations

*Financial Results from Continuing Operations*

| | 2004 | | | | 2003 | | | | 2002 | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| *($ millions)* | Produced Gas | Crude Oil and NGLs | Other | Total | Produced Gas | Crude Oil and NGLs | Other | Total | Produced Gas | Crude Oil and NGLs | Other | Total |
| Revenues, Net of Royalties | $5,704 | $1,320 | $ 232 | $7,256 | $4,447 | $1,170 | $ 180 | $5,797 | $2,280 | $ 970 | $ 76 | $3,326 |
| Expenses | | | | | | | | | | | | |
| Production and mineral taxes | 270 | 41 | – | 311 | 153 | 11 | – | 164 | 82 | 23 | – | 105 |
| Transportation and selling | 416 | 56 | – | 472 | 360 | 69 | – | 429 | 210 | 35 | – | 245 |
| Operating | 519 | 285 | 222 | 1,026 | 402 | 300 | 170 | 872 | 290 | 201 | 71 | 562 |
| Operating Cash Flow | $4,499 | $938 | $ 10 | $5,447 | $3,532 | $ 790 | $ 10 | $4,332 | $1,698 | $ 711 | $ 5 | $2,414 |
| Depreciation, depletion and amortization | | | | 2,271 | | | | 1,900 | | | | 1,115 |
| Upstream Income | | | | $3,176 | | | | $2,432 | | | | $1,299 |

### 2004 vs. 2003

Results from continuing operations reflect a 12 percent increase in sales volumes of 418 MMcfe/d (69,689 BOE/d) for the year ended December 31, 2004 compared with 2003.

Revenues, net of royalties, reflect the increase in natural gas and crude oil benchmark prices (see the "Business Environment" section of this MD&A) for the year offset by the realized hedging losses. The effect of realized commodity and currency hedging losses for the year ended December 31, 2004 was $669 million, or $0.46 per Mcfe ($2.77 per BOE), compared to $297 million or $0.23 per Mcfe ($1.38 per BOE) for 2003.

North American production and mineral taxes for produced gas increased 76 percent in 2004 compared to 2003 primarily due to increased natural gas prices and volumes in the United States and a higher effective tax rate on production growth in Colorado.

Transportation and selling expenses increased ten percent in 2004 as a result of increased natural gas volumes in the U.S. and Canada and the impact of the change in the average U.S./Canadian dollar exchange rate on Canadian dollar denominated transactions.

For the year ended December 31, 2004, operating expenses were slightly higher at $0.55 per Mcfe ($3.33 per BOE) compared to $0.54 per Mcfe ($3.26 per BOE) for the same period in 2003 due primarily to the increase in the average U.S./Canadian dollar exchange rate during 2004. Excluding the impact of foreign exchange, operating expenses in 2004 would have decreased to $0.51 per Mcfe ($3.10 per BOE) primarily as a result of increased volumes.

DD&A expense increased by $371 million in 2004 compared to 2003 primarily as a result of increased sales volumes and the impact of the higher value of the Canadian dollar compared to the U.S. dollar applied to Canadian dollar denominated DD&A expense. On a North America basis, excluding Other activities, DD&A rates were $1.53 per Mcfe ($9.20 per BOE) for 2004 compared to $1.39 per Mcfe ($8.36 per BOE) in 2003. Increased DD&A rates in 2004 were primarily the result of the increase in the average U.S./Canadian dollar exchange rate and the impact of the acquisition cost of TBI. DD&A rates for the year ended December 31, 2004 exclude impairments of exploration prospects in Ghana, Bahrain and other areas of $23 million which were recorded in the second and fourth quarters of 2004, respectively.

### 2003 vs. 2002

The Company's 2003 Upstream revenues, net of royalties, increased $2,471 million, or 74 percent, over 2002 due to the increase in commodity prices, growth in sales volumes and the inclusion of a full year of post merger results. The 23 percent growth in sales volumes from continuing operations of 675 MMcfe/d (112,585 BOE/d) for the year ended December 31, 2003, compared to 2002, reflected increased production in the U.S., the addition of a full year of post merger volumes and the expansion of production from the Company's Steam Assisted Gravity Drainage ("SAGD") projects.

Production and mineral tax increases in 2003 were the result of higher prices in the U.S. and a full year of post merger results.

The increased transportation and selling expenses in 2003 were attributable to growth in North American volumes, a full year of post merger results and the effect of the change in the average U.S./Canadian dollar exchange rate on Canadian dollar denominated transportation and selling expenses.

Upstream operating costs increased 55 percent compared to 2002 due to additional production volumes, a full year of post merger results, the change in the average U.S./Canadian dollar exchange rate and its impact on Canadian dollar denominated operating expenses, as well as increased costs for maintenance, workovers, higher fuel and power expense due to higher natural gas prices and an increased proportionate share of costs from SAGD operations.

DD&A expense increased by $785 million in 2003 compared to 2002. On a North America basis, excluding Other activities, DD&A rates were $1.39 per Mcfe ($8.36 per BOE) for 2003 compared to $1.01 per Mcfe ($6.09 per BOE) in 2002. The increased DD&A rate in 2003 reflects increased future development costs related to the proved reserves added for SAGD projects and the U.S., and the effect of the increase in the average U.S./Canadian dollar exchange rate on the Canadian dollar denominated DD&A expense.

*Revenue Variances for 2004 Compared to 2003 and 2003 Compared to 2002 from Continuing Operations*

| | 2004 | | | | 2003 | | | |
|---|---|---|---|---|---|---|---|---|
| *($ millions)* | 2003 Revenues, Net of Royalties | Revenue Variances in: Price (1) | Volume | 2004 Revenues, Net of Royalties | 2002 Revenues, Net of Royalties | Revenue Variances in: Price (1) | Volume | 2003 Revenues, Net of Royalties |
| Produced Gas | | | | | | | | |
| Canada | $ 3,396 | $ 271 | $ 261 | $ 3,928 | $ 1,882 | $ 1,075 | $ 439 | $ 3,396 |
| United States | 1,051 | 147 | 578 | 1,776 | 398 | 204 | 449 | 1,051 |
| Total Produced Gas | $ 4,447 | $ 418 | $ 839 | $ 5,704 | $ 2,280 | $ 1,279 | $ 888 | $ 4,447 |
| Crude Oil and NGLs | | | | | | | | |
| Canada | $ 1,078 | $ 95 | $ (18) | $ 1,155 | $ 914 | $ (11) | $ 175 | $ 1,078 |
| United States | 92 | 30 | 43 | 165 | 56 | 6 | 30 | 92 |
| Total Crude Oil and NGLs | $ 1,170 | $ 125 | $ 25 | $ 1,320 | $ 970 | $ (5) | $ 205 | $ 1,170 |

*(1) Includes realized commodity and currency hedging impacts.*

The increase in sales volumes accounts for approximately 61 percent of the change in revenues, net of royalties, for 2004 compared with 2003. In the table above, impacts from price changes are reduced as a result of the year over year changes in realized commodity and currency hedge losses mentioned previously.

The Crude Oil and NGLs volume variance in Canada of $(18) million for 2004 compared with 2003 was mainly due to the dispositions of mature conventional producing assets during 2004.

| *Sales Volumes* | 2004 | 2004 vs 2003 | 2003 | 2003 vs 2002 | 2002 |
|---|---|---|---|---|---|
| Produced Gas *(million cubic feet per day)* | 2,968 | 16% | 2,553 | 25% | 2,048 |
| Crude Oil *(barrels per day)* | 140,379 | -1% | 142,326 | 21% | 117,218 |
| NGLs *(barrels per day)* | 26,038 | 10% | 23,569 | 16% | 20,259 |
| Continuing Operations *(million cubic feet equivalent per day)* (1) | 3,966 | 12% | 3,548 | 23% | 2,873 |
| Continuing Operations *(barrels of oil equivalent per day)* (2) | 661,084 | 12% | 591,395 | 23% | 478,810 |
| Discontinued Operations | | | | | |
| Ecuador *(barrels per day)* | 77,993 | 68% | 46,521 | 56% | 29,740 |
| United Kingdom *(barrels of oil equivalent per day)* (2) | 20,973 | 71% | 12,295 | 1% | 12,195 |
| Syncrude *(barrels per day)* | – | – | 7,629 | -68% | 23,540 |
| Discontinued Operations *(million cubic feet equivalent per day)* (1) | 594 | 49% | 399 | 2% | 393 |
| Total *(million cubic feet equivalent per day)* (1) | 4,560 | 16% | 3,947 | 21% | 3,266 |
| Total *(barrels of oil equivalent per day)* (2) | 760,050 | 16% | 657,840 | 21% | 544,285 |

*(1) Liquids converted to thousand cubic feet equivalent at 1 barrel = 6 thousand cubic feet.*
*(2) Includes natural gas and liquids (converted to BOE).*

In 2004, volumes from continuing operations were higher by 12 percent, or 418 MMcfe/d (69,689 BOE/d), compared to 2003.

Canadian natural gas sales volumes increased approximately seven percent or 134 MMcf/d in 2004. This increase results mostly from successful resource play drilling programs at Greater Sierra and Cutbank Ridge in northeast British Columbia as well as Shallow Gas in southern Alberta; the increased volumes were partially reduced by the disposition of non-core properties during 2004, producing approximately 56 MMcf/d on an annualized basis. Natural gas sales volumes in the United States increased approximately 48 percent or 281 MMcf/d during 2004 primarily due to successful resource play drilling programs in the Piceance and Fort Worth basins and incremental production of 161 MMcf/d from the TBI acquisition.

In 2004, liquids sales volumes were relatively unchanged when compared to 2003. The impacts of continued development at Foster Creek, successful drilling programs at Suffield and Weyburn, and positive response from the waterflood program at Pelican Lake were offset by the Petrovera and other non-core dispositions in the first and third quarters of 2004, respectively, which reduced production by 19,800 bbls/d on an annualized basis.

### Highlights

**Greater Sierra**

Natural gas production averaged 230 MMcf/d, an increase of 61 percent (or 87 MMcf/d) in 2004 mainly due to the success of the 2003/2004 drilling program. In 2004, 187 net wells were drilled.

**Cutbank Ridge**

2004 was the first full year of operations. Natural gas production averaged 40 MMcf/d and exited the year at 47 MMcf/d. In 2004, 50 net wells were drilled.

**Coalbed Methane**

Natural gas production in 2004 exited the year at 30 MMcf/d and averaged 17 MMcf/d up from 4 MMcf/d in 2003. During the year, 577 net wells were drilled.

**Shallow Gas**

During 2004, natural gas production increased 17 percent to 592 MMcf/d with 1,552 net wells drilled.

**Piceance**

Natural gas production averaged 261 MMcf/d in 2004, an increase of 73 percent or 110 MMcf/d compared to 2003. This increase is the result of a successful drilling program (250 net wells) and the TBI acquisition.

**Fort Worth**

EnCana acquired assets in the Fort Worth Basin in 2003 with the Savannah Energy Inc. acquisition and added to those assets as a result of a December 2004 property acquisition. Production averaged 27 MMcf/d in 2004.

**East Texas**

East Texas, which produced 50 MMcf/d during 2004, was acquired as part of the TBI acquisition. During 2004, 50 net wells were drilled.

**Foster Creek**

Completion of the first phase of facility expansion in the fall of 2003 resulted in a 32 percent increase in 2004 crude oil production to 28,800 bbls/d.

**Pelican Lake**

Average crude oil production in 2004 increased 19 percent to 18,900 bbls/d due to the response of the waterflood program which began in the last half of 2004.

**Per Unit Results – Produced Gas**

| *($ per thousand cubic feet)* | Canada | | | | | United States | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2004 | 2004 vs 2003 | 2003 | 2003 vs 2002 | 2002 | 2004 | 2004 vs 2003 | 2003 | 2003 vs 2002 | 2002 |
| Price (1) | $ 5.34 | 10% | $ 4.87 | 70% | $ 2.86 | $ 5.79 | 19% | $ 4.88 | 65% | $ 2.96 |
| Expenses | | | | | | | | | | |
| Production and mineral taxes | 0.08 | 14% | 0.07 | -13% | 0.08 | 0.65 | 38% | 0.47 | 74% | 0.27 |
| Transportation and selling (2) | 0.39 | 3% | 0.38 | 58% | 0.24 | 0.31 | -23% | 0.40 | -15% | 0.47 |
| Operating | 0.52 | 8% | 0.48 | 17% | 0.41 | 0.37 | 32% | 0.28 | – | 0.28 |
| Netback | $ 4.35 | | $ 3.94 | | $ 2.13 | $ 4.46 | | $ 3.73 | | $ 1.94 |
| Gas Sales Volumes *(MMcf per day)* | 2,099 | 7% | 1,965 | 15% | 1,711 | 869 | 48% | 588 | 74% | 337 |

*(1) Excludes realized commodity and currency hedge activities.*
*(2) U.S. per unit transportation and selling costs in 2004 exclude a one-time payment of $21 million made to terminate a long-term physical delivery contract.*

Benchmark natural gas NYMEX prices were higher by 14 percent compared with 2003, however this increase has been partially offset by increased natural gas price differentials in Canada. For the year ended December 31, 2004, realized commodity and currency hedging losses on natural gas were approximately $238 million, or $0.22 per Mcf compared to a loss of approximately $91 million, or $0.10 per Mcf in 2003. Certain of these hedges were put in place to secure the economics of the TBI acquisition.

Per unit production and mineral taxes in the U.S. for the year ended December 31, 2004 compared to 2003 increased 38 percent or $0.18 per Mcf due to a combination of higher gas prices and a higher effective tax rate on the significant production growth in Colorado.

Natural gas per unit transportation and selling costs for the U.S. have decreased 23 percent or $0.09 per Mcf for the year ended December 31, 2004 compared to 2003, primarily as a result of the TBI acquisition where a majority of the production is sold at the wellhead and does not incur transportation charges.

Canadian natural gas per unit operating expenses for 2004 were eight percent or $0.04 per Mcf higher compared to 2003 primarily due to the higher U.S./Canadian exchange rates. Increases in the U.S. per unit natural gas operating expenses of 32 percent or $0.09 per Mcf for the year ended December 31, 2004 compared to 2003 were a result of higher operating expenses from the TBI properties, incremental operating costs associated with waste water disposal in Colorado and other non-recurring charges related to the prior year.

Average realized prices for natural gas in the U.S. and Canada for 2003 increased by approximately 65 percent and 70 percent, respectively, over 2002 due to concerns about overall North American storage inventory levels and a lack of confidence concerning prospects for North American supply growth. Realized commodity and currency hedging gains in 2002 for natural gas were $66 million, or $0.09 per Mcf.

Per unit production and mineral tax expense in the U.S. was $0.20 per Mcf higher in 2003 than 2002 due to higher natural gas prices.

For Canadian produced gas operations, per unit transportation and selling costs were higher in 2003 compared to 2002 by $0.14 per Mcf due to an increased proportion of sales transported to more distant markets and the change in the U.S./Canadian dollar exchange rate.

Per unit operating expenses for Canadian produced gas were higher in 2003 compared to 2002 by $0.07 per Mcf as a result of increased maintenance, workovers, the effect of the change in the U.S./Canadian dollar exchange rate and production from higher operating cost areas.

| ***Per Unit Results – Crude Oil*** *($ per barrel)* | North America | | | | |
|---|---|---|---|---|---|
| | 2004 | 2004 vs 2003 | 2003 | 2003 vs 2002 | 2002 |
| Price (1) | $ 27.92 | 25% | $ 22.29 | 11% | $ 20.08 |
| Expenses | | | | | |
| Production and mineral taxes | 0.41 | 356% | 0.09 | -79% | 0.43 |
| Transportation and selling | 1.06 | -19% | 1.31 | 60% | 0.82 |
| Operating | 5.53 | -5% | 5.80 | 24% | 4.69 |
| Netback | $ 20.92 | | $ 15.09 | | $ 14.14 |
| Crude Oil Sales Volumes *(bbls per day)* | 140,379 | -1% | 142,326 | 21% | 117,218 |

*(1) Excludes realized commodity and currency hedge activities.*

Increases in the average crude oil price in 2004, excluding the impact of financial hedges, reflect the increase in the benchmark WTI which increased 34 percent in 2004 compared to 2003. This increase was partially offset by the increased WTI/Bow River crude oil price differential (up approximately 60 percent) and a higher proportionate share of heavier blend oils in the product mix. Realized commodity and currency hedging losses on crude oil were approximately $431 million, or $7.08 per bbl of liquids in 2004 compared to a loss of approximately $206 million, or $3.41 per bbl of liquids in 2003.

North American per unit production and mineral taxes increased in 2004 primarily as a result of mineral tax amendments related to prior years that were recorded in the third quarter of 2003. Higher freehold mineral tax and Saskatchewan surtax in the Weyburn area resulted from higher prices and increased production.

The 2004 per unit crude oil transportation and selling expenses in North America have decreased $0.25 per bbl mainly due to an adjustment in oil transportation rates.

North American crude oil per unit operating costs for 2004 have decreased $0.27 per bbl compared to 2003 mainly due to the sale of Petrovera, which had higher operating costs relative to other properties. This reduction was partially offset by the effect of increased U.S./Canadian exchange rates and higher fuel gas costs for the SAGD projects.

Average realized crude oil prices in 2003 increased approximately 11 percent over 2002 as a result of concerns over tensions in the Middle East combined with strong Asian demand and OPEC's management of its production quotas. Realized commodity and currency hedging losses in 2002 on crude oil were $32 million, or $0.64 per bbl of liquids.

Per unit transportation and selling costs were higher by $0.49 per bbl over 2002 as a result of increased heavy crude oil volumes which attract a 20 percent premium transportation charge over light crude oil combined with annual tariff increases.

The increase in per unit operating expenses of $1.11 per bbl for 2003 compared to 2002 is attributable to the increase in the U.S./Canadian dollar exchange rate, higher maintenance costs and increased production weighting of heavy oil volumes from SAGD projects, which have higher operating expenses, combined with higher fuel and electricity costs resulting from the rise in natural gas prices.

*Per Unit Results – NGLs* (1)

| ($ per barrel) | Canada | | | | | United States | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2004 | 2004 vs 2003 | 2003 | 2003 vs 2002 | 2002 | 2004 | 2004 vs 2003 | 2003 | 2003 vs 2002 | 2002 |
| Price | $ 31.43 | 30% | $ 24.26 | 38% | $ 17.55 | $ 35.43 | 31% | $ 26.97 | 14% | $ 23.75 |
| Expenses | | | | | | | | | | |
| Production and mineral taxes | – | – | – | – | – | 3.82 | 88% | 2.03 | 99% | 1.02 |
| Transportation and selling | 0.41 | 141% | 0.17 | – | – | – | – | – | – | – |
| Netback | $ 31.02 | | $ 24.09 | | $ 17.55 | $ 31.61 | | $ 24.94 | | $ 22.73 |
| NGLs Sales Volumes *(bbls per day)* | 13,452 | -6% | 14,278 | 3% | 13,852 | 12,586 | 35% | 9,291 | 45% | 6,407 |

*(1) NGLs results include condensate.*

NGLs realized price changes generally correlate with changes in WTI oil prices. The strong WTI oil price in 2004 positively impacted NGLs prices.

U.S. per unit production and mineral taxes for the year ended December 31, 2004 compared to 2003 increased by 88 percent or $1.79 per bbl. Higher NGLs prices in 2004 and increased production growth in Colorado, which has a higher effective production tax rate, were the key reasons for this increase.

Per unit transportation and selling costs for NGLs in Canada increased by 141 percent or $0.24 per bbl in 2004 compared to 2003 as the Company incurred a full year of trucking charges for volumes in northeast British Columbia that came onstream in the fall of 2003.

## Midstream & Market Optimization Operations

*Financial Results*

| | 2004 | | | 2003 | | | 2002 | | |
|---|---|---|---|---|---|---|---|---|---|
| ($ millions) | Midstream | Market Optimization | Total | Midstream | Market Optimization | Total | Midstream | Market Optimization | Total |
| Revenues | $ 1,450 | $ 3,299 | $ 4,749 | $ 1,084 | $ 2,803 | $ 3,887 | $ 440 | $ 2,154 | $ 2,594 |
| Expenses | | | | | | | | | |
| Transportation and selling | – | 27 | 27 | – | 55 | 55 | – | 87 | 87 |
| Operating | 279 | 46 | 325 | 261 | 63 | 324 | 174 | 13 | 187 |
| Purchased product | 1,071 | 3,205 | 4,276 | 762 | 2,693 | 3,455 | 169 | 2,031 | 2,200 |
| Operating Cash Flow | $ 100 | $ 21 | $ 121 | $ 61 | $ (8) | $ 53 | $ 97 | $ 23 | $ 120 |
| Depreciation, depletion and amortization | | | 70 | | | 48 | | | 36 |
| Segment Income | | | $ 51 | | | $ 5 | | | $ 84 |

Revenues and purchased product expense in Midstream & Market Optimization operations increased in 2004 compared to 2003 due primarily to increases in commodity prices. Operating cash flow increased $68 million in 2004 to $121 million as a result of improved margins from natural gas liquids processing and gas storage optimization activities. Decreases in transportation and selling costs in 2004 compared to 2003 are primarily due to the reallocation of natural gas downstream transportation costs to the Upstream segment. Operating expenses in 2003 included a $20 million settlement with the U.S. Commodity Futures Trading Commission as described in the "Contractual Obligations and Contingencies" section of this MD&A.

The increase in 2004 DD&A is primarily due to a write down in the value of the Company's equity investment interest in the Trasandino Pipeline in Argentina and Chile of approximately $35 million.

## Corporate

| ($ millions) | 2004 | 2003 | 2002 |
|---|---|---|---|
| Revenues | $ (195) | $ 2 | $ 8 |
| Expenses | | | |
| Operating | (1) | – | – |
| Depreciation, depletion and amortization | 61 | 41 | 35 |
| Segment Income | $ (255) | $ (39) | $ (27) |
| Administrative | 197 | 173 | 118 |
| Interest, net | 397 | 283 | 286 |
| Accretion of asset retirement obligation | 22 | 17 | 13 |
| Foreign exchange gain | (417) | (598) | (11) |
| Stock-based compensation | 17 | 18 | – |
| Gain on dispositions | (113) | (1) | (33) |
| Income tax expense | 658 | 364 | 317 |

Corporate revenues in 2004 include approximately $197 million in unrealized mark-to-market losses related to financial and commodity contracts. Other mark-to-market gains ($7 million) on derivative financial instruments related to interest and electricity consumption are recorded in interest, net and operating expenses respectively.

DD&A includes provisions for corporate assets such as computer equipment, office furniture and leasehold improvements. The increase in expense on a year-over-year basis is the result of higher capital spending in prior periods on corporate capital items and the impact of the change in the U.S./Canadian dollar exchange rate.

Administrative expenses increased 14 percent in 2004. The increase reflects the effect of the change in the U.S./Canadian dollar exchange rate and increased long-term compensation expenses. Administrative costs were approximately $0.12 per Mcfe in both 2004 and 2003.

The higher interest expense resulted primarily from the higher average outstanding debt level during the year as a result of the TBI acquisition in the second quarter of 2004. EnCana's weighted average interest rate on outstanding debt was marginally lower in 2004 than it was in 2003 and partially mitigated the effect of higher debt levels.

The majority of the foreign exchange gain of $417 million in 2004 resulted from the change in the U.S./Canadian dollar exchange rate during 2004 applied to U.S. dollar denominated debt issued in Canada as discussed previously in this MD&A. Under Canadian GAAP, the Company is required to translate long-term debt issued in Canada and denominated in U.S. dollars into Canadian dollars at the period-end exchange rate. Resulting foreign exchange gains or losses are recorded in the Consolidated Statement of Earnings.

During 2004, EnCana sold certain corporate investments and recorded gains of $113 million on these sales.

The effective tax rate for 2004 was 23 percent compared to 15 percent for 2003 and 32 percent for 2002. Further information regarding EnCana's effective tax rate can be found in Note 9 to the Consolidated Financial Statements. EnCana's effective rate in any year is a function of the relationship between the amount of net earnings before income taxes for the year and the magnitude of the items representing "permanent differences" that are excluded from the earnings subject to tax. There are a variety of items of this type, including:

- The effects of asset dispositions where the tax values of the assets sold differ from their accounting value.
- Adjustments for the impact of legislative tax changes which have a prospective impact on future income tax obligations.
- The non-taxable half of Canadian capital gains (losses).
- Items such as resource allowance and non-deductible crown payments where the income tax treatment is different from the accounting treatment.

The 2004 effective tax rate reflects a reduction of $109 million in future income taxes resulting from the reduction in the Alberta tax rate from 12.5 percent to 11.5 percent and Alberta's retention of the resource allowance and non-deductible crown royalties regime until 2007. In 2003, the effective tax rate reflected a $359 million reduction in future income taxes resulting from the reductions in the Canadian federal and Alberta corporate income tax rates and related changes to the Canadian federal resource allowance deduction.

Current income tax expense for the year ended 2004 was $567 million compared to $(113) million in 2003 and $(66) million in 2002. As expected, current taxes increased significantly in 2004: 2003 and 2002 were abnormally low as a result of the effects of the merger with Alberta Energy Company Ltd.

The operations of the Company are complex and related tax interpretations, regulations and legislation in the various jurisdictions that the Company and its subsidiaries operate in are continually changing. As a result, there are usually some tax matters under review. The Company believes that the provision for taxes is adequate.

## Capital Expenditures

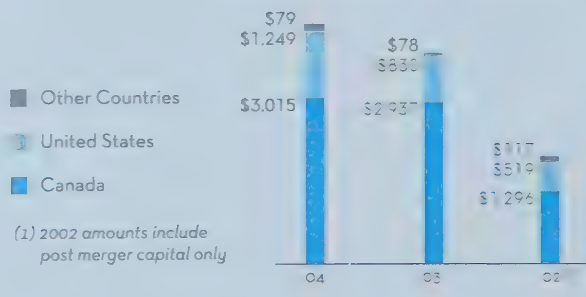
***Capital Summary***
*($ millions)*

| | 2004 | 2003 | 2002 (1) |
|---|---|---|---|
| Upstream | $ 4,343 | $ 3,845 | $ 1,932 |
| Midstream & Market Optimization | 64 | 223 | 47 |
| Corporate | 46 | 57 | 43 |
| Core Capital Expenditures | $ 4,453 | $ 4,125 | $ 2,022 |
| Acquisitions | 2,986 | 593 | 748 |
| Dispositions | (1,817) | (301) | (423) |
| Discontinued Operations | (1,416) | (995) | 397 |
| Net Capital | $ 4,206 | $ 3,422 | $ 2,744 |

*(1) 2002 amounts include post merger capital only.*

The Company's core capital expenditures increased approximately $0.3 billion to $4.5 billion in 2004. The increase in Upstream core capital expenditures in 2004 compared to 2003 was primarily as a result of continued development of EnCana's United States resource play properties. Net capital expenditures increased approximately $0.8 billion compared to 2003 as a result of the TBI acquisition, increased drilling in the U.S., higher cost wells drilled both in Canada and the U.S., and the impact of the higher U.S./Canadian dollar exchange rate partially offset by the sale of the U.K. operations and non-core asset dispositions. The Company's capital investment was funded by cash flow in excess of amounts paid for purchases of Common Shares under the Normal Course Issuer Bid, proceeds received on dispositions of non-core assets and debt.

***Upstream Core Capital for Continuing Operations***
*($ millions)*




### *Upstream Capital Expenditures*

The increase in Upstream capital expenditures in 2004 compared to 2003 reflects increased drilling and development activities in the U.S. and the impact of the increased average U.S./Canadian dollar exchange rate on Canadian dollar denominated expenditures. On an annual basis the change in the average U.S./Canadian dollar exchange rate resulted in an increase on Canadian dollar denominated core capital expenditures of approximately $230 million. Capital spending during 2004 was primarily focused on North American resource play properties. Natural gas capital expenditures were primarily focused on continued development of the Company's key resource plays in Greater Sierra, Cutbank Ridge and Shallow Gas in Canada, and Piceance, Jonah, East Texas and Fort Worth in the United States. Crude oil capital spending in 2004 was concentrated at Foster Creek, Pelican Lake and Suffield in Alberta and Weyburn in Saskatchewan. The Company drilled 4,923 net wells in 2004 compared to 5,581 net wells in 2003.

*Canadian East Coast*

In 2004, the Company participated in two deep water tests at Weymouth and Crimson. Both of these wells were plugged and abandoned. As of December 31, 2004, the Company's investment in its East Coast assets, including Deep Panuke, is recorded at approximately $371 million. Until assessments of the economics of the Panuke project are complete, the timing of any potential start of production and amount of additional costs which may be incurred are not determinable.

*Gulf of Mexico*

During 2004, the Company's operating partner completed a well test at the Tahiti oilfield which is located 304 kilometres southwest of New Orleans. As of December 31, 2004, the Company had invested approximately $394 million in the Gulf of Mexico, including Tahiti. The field is expected to begin production in 2008. The Company has announced that it intends to sell its interests in the Gulf of Mexico.

*Reserves*

Each year, EnCana engages independent qualified reserve evaluators to prepare reports on 100 percent of the Corporation's oil and natural gas reserves. The Company has a Reserves Committee of independent board members which reviews the qualifications and appointment of the independent qualified reserve evaluators. The Committee also reviews the procedure for providing information to the evaluators. EnCana's disclosure of reserves data is covered by NI 51-101 as amended by a Mutual Reliance Review System Decision Document dated December 16, 2003 permitting the adoption of U.S. reporting standards, including compliance with the practices and procedures of U.S. Securities and Exchange Commission ("SEC") and Financial Accounting Standards Board ("FASB") reserve reporting requirements, in 2003. These standards require that reserves be estimated employing the single day field price of the commodity at the effective date of the valuation – in this case December 31, 2004.

EnCana's proved natural gas reserves as at December 31, 2004, on an SEC constant price basis, totalled 10,460 Bcf. Extensions and discoveries resulting from successful exploration and development capital programs amounted to 2,431 Bcf. Downward revisions of 252 Bcf in the United States were largely the result of reduced reserves estimates per well in the northern and southern Rockies. Net acquisitions were dominated by the purchase of TBI in May 2004.

The Company's proved crude oil and natural gas liquids reserves as at December 31, 2004, on an SEC constant price basis, totalled 501 MMbbls. Extensions and discoveries resulting from successful exploration and development capital programs amounted to 163 MMbbls. Downward revisions in Canada were dominated by a 363 MMbbls adjustment at Foster Creek necessitated by reliance on year-end prices for bitumen determined in accordance with SEC and FASB requirements. If EnCana were applying the approach set out by the Canadian Securities Administrators in their Staff Notice 51-315, dated January 20, 2005, namely the use of the average price differential for the preceding 12 months, it is expected that no negative revisions to the company's proved bitumen reserves would occur. Divestitures were dominated by the sale of all of EnCana's interests in the U.K. central North Sea and non-core interests in Western Canada.

***Proved Reserves by Country***

| *Constant Prices After Royalties* | Natural Gas | | | | | Crude Oil and NGLs (1) | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| *As at December 31* | **2004** | **2004 vs 2003** | 2003 | 2003 vs 2002 | 2002 | **2004** | **2004 vs 2003 (2)** | 2003 | 2003 vs 2002 | 2002 |
| | *(billions of cubic feet)* | | | | | *(millions of barrels)* | | | | |
| Canada | **5,824** | **11%** | 5,256 | 4% | 5,073 | **267** | **-58%** | 629 | 16% | 542 |
| United States | **4,636** | **48%** | 3,129 | 22% | 2,573 | **91** | **117%** | 42 | 2% | 41 |
| Ecuador | **–** | **–** | – | – | – | **143** | **-12%** | 162 | 4% | 156 |
| United Kingdom | **–** | **-100%** | 26 | 30% | 20 | **–** | **-100%** | 124 | 28% | 97 |
| Total | **10,460** | **24%** | 8,411 | 10% | 7,666 | **501** | **-48%** | 957 | 14% | 836 |

*(1) NGLs include condensate.*

*(2) Year-end 2004 Canadian crude oil and NGL's reserves were essentially unchanged from the previous year, prior to the bitumen revision caused by an anomalously low December 31, 2004 field price.*

### *Proved Reserves Reconciliation by Country*

*Constant Prices After Royalties*

| *As at December 31, 2004* | Natural Gas *(billions of cubic feet)* Canada | USA | UK | Total | Crude Oil and NGLs (1) *(millions of barrels)* Canada | USA | Ecuador | UK | Total |
|---|---|---|---|---|---|---|---|---|---|
| Beginning of year | 5,256 | 3,129 | 26 | 8,411 | 629 | 42 | 162 | 124 | 957 |
| Revisions and improved recovery | 67 | (252) | – | (185) | 32 | – | (12) | – | 20 |
| Extensions and discoveries | 1,422 | 1,009 | – | 2,431 | 94 | 48 | 21 | – | 163 |
| Acquisitions | 65 | 1,150 | 10 | 1,225 | 29 | 12 | – | 10 | 51 |
| Divestitures | (215) | (82) | (25) | (322) | (97) | (6) | – | (128) | (231) |
| Production | (771) | (318) | (11) | (1,100) | (57) | (5) | (28) | (6) | (96) |
| End of year before bitumen revisions | 5,824 | 4,636 | – | 10,460 | 630 (3) | 91 | 143 | – | 864 |
| Revisions due to bitumen price (2) | – | – | – | – | (363) | – | – | – | (363) |
| End of year | 5,824 | 4,636 | – | 10,460 | 267 | 91 | 143 | – | 501 |

*(1) NGLs include condensate.*

*(2) As a result of using year-end price.*

*(3) Year-end 2004 Canadian crude oil and NGL's reserves were essentially unchanged from the previous year, prior to the bitumen revision caused by an anomalously low December 31, 2004 field price.*

### Midstream & Market Optimization Capital Expenditures

Expenditures in 2004 related primarily to ongoing improvements to midstream facilities.

### Corporate Capital Expenditures

Corporate capital expenditures relate primarily to spending on business information systems, leasehold improvements and furniture and office equipment.

## DISCONTINUED OPERATIONS

United Kingdom and Ecuador assets are presented as discontinued operations in the Consolidated Financial Statements. EnCana's net earnings from discontinued operations are $1,302 million and include a gain of $1,364 million on the discontinuance of U.K. operations, realized financial and commodity hedge losses of $358 million and unrealized financial and commodity hedge losses of $71 million. Summary information is presented below. Additional information concerning EnCana's discontinued operations can be found in Note 5 to EnCana's Consolidated Financial Statements.

### UNITED KINGDOM

| | 2004 | 2003 | 2002 |
|---|---|---|---|
| Sales volumes | | | |
| Produced Gas *(million cubic feet per day)* | 30 | 13 | 10 |
| Crude Oil *(barrels per day)* | 14,128 | 9,231 | 9,733 |
| NGLs *(barrels per day)* | 1,845 | 897 | 795 |
| Total *(million cubic feet equivalent per day)* | 126 | 74 | 73 |
| *($ millions)* | | | |
| Net earnings (loss) from discontinued operations | $ 1,338 | $ (7) | $ 24 |
| Capital Investment | 488 | 223 | 82 |

In December 2004, a subsidiary of the Company completed the sale of its U.K. central North Sea assets, production and prospects for net cash consideration of approximately $2.1 billion, resulting in a gain on sale of approximately $1.4 billion.

Liquids sales volumes in 2004 increased to 15,973 bbls/d from 10,128 bbls/d in 2003 primarily as a result of the acquisitions of additional interests in the Scott and Telford fields in October 2003 and February 2004. Higher transportation and selling expenses in 2004 compared to 2003 of $20 million were primarily due to higher product volumes. Operating expenses increased approximately $18 million in 2004 due to a platform turnaround, higher maintenance costs and higher volumes. Increased DD&A expense in 2004 of $44 million over 2003 was primarily due to increased volumes offset by a decrease in the DD&A rate.

## ECUADOR

| | 2004 | 2003 | 2002 |
|---|---|---|---|
| Sales volumes | | | |
| Crude Oil *(barrels per day)* | **77,993** | 46,521 | 29,740 |
| *($ millions)* | | | |
| Net (loss) earnings from discontinued operations | **$ (33)** | $ 32 | $ 45 |
| Capital Investment | **240** | 367 | 169 |

At December 31, 2004, EnCana has decided to sell its Ecuador operations and accordingly the Ecuador operations have been accounted for as discontinued operations.

Sales volumes in 2004 increased 68 percent to average approximately 78,000 bbls/d. The increased sales volumes are primarily due to the combination of available capacity on the OCP pipeline in Ecuador and increased production from Block 15.

Production and mineral taxes were $36 million higher in 2004 compared to 2003 as a result of higher realized prices and volumes on the Tarapoa block. The Company is required to pay a percentage of revenue from this block to the Ecuador government based on realized prices over a base price. Operating costs were $42 million higher in 2004 compared to 2003 due to higher workover costs and increased fuel and diesel costs and higher maintenance and personnel costs on Block 15. DD&A expense increased $104 million compared to 2003 as a result of higher crude oil volumes.

Crude oil sales volumes increased 56 percent in 2003, compared to 2002, due to the inclusion of a full year of post merger volumes and the removal of transportation capacity constraints as a result of the commencement of shipments on the OCP pipeline in September 2003. Higher production and mineral taxes in 2003, compared to 2002 resulted from increased production from the Tarapoa block and higher realized prices from Tarapoa volumes. Transportation and selling costs were higher in 2003 and reflect the higher tariff on OCP pipeline compared to the SOTE pipeline system. Operating expenses and DD&A increased in 2003 compared to 2002 primarily due to higher crude oil volumes.

Contingency information concerning Ecuador discontinued operations is included in Note 5 to EnCana's Consolidated Financial Statements.

# LIQUIDITY AND CAPITAL RESOURCES

EnCana's cash flow from continuing operations was $4,605 million in 2004, up $470 million compared to 2003. The increase in cash flow was primarily due to increased revenues from the growth in sales volumes and higher commodity prices offset by higher realized commodity and currency hedging losses, an increase in the current tax provision and an increase in the U.S./Canadian dollar exchange rate.

During 2004, long-term debt plus the current portion of long-term debt increased $1,555 million. This increase resulted from the acquisition of TBI and capital spending, offset by proceeds of dispositions and increased cash flow during 2004, including proceeds of $2.1 billion received from the sale of the U.K. assets on December 1, which were used to repay bank and other indebtedness. EnCana's net debt adjusted for working capital was $7,184 million as at December 31, 2004 compared with $5,544 million at December 31, 2003. Working capital was $558 million and included unrealized losses on mark-to-market accounting on derivatives of $95 million and a current tax payable of $359 million. This compares to a working capital of $544 million as at December 31, 2003. Cash flow together with proceeds from dispositions were used for the purchase of shares under the Company's Normal Course Issuer Bid and capital expenditures.

Net debt to capitalization at the end of 2004 is 33 percent, unchanged from 2003. Management calculates this ratio for internal purposes to steward the Company's overall debt position as a measure of a company's financial strength.

EnCana's long-term credit ratings were confirmed by Standard & Poor's and Dominion Bond Rating Services credit rating agencies in October 2004. Standard & Poor's has affirmed an A- with a 'Negative Outlook' and Dominion Bond Rating Services has affirmed an A(low) with a 'Stable Trend'. Moody's long-term credit rating for EnCana remains at 'Baa2 Stable'. The agencies are expected to continue to monitor the Company's operating and financial performance through the first quarter of 2005.

On March 23, 2004 the Company redeemed all of its Coupon Reset Subordinated Term Securities, Series A ("Term Securities") which had an aggregate principal amount of approximately C$126 million. The redemption price of the Term Securities was the principal amount plus accrued and unpaid interest to the redemption date.

In March 2004, an indirect wholly owned subsidiary, EnCana Holdings Finance Corp. ("EHFC"), filed a shelf prospectus whereby it may issue from time to time up to $2 billion of debt securities. Debt securities issued under this shelf prospectus are unconditionally guaranteed by EnCana Corporation. On May 13, 2004 EHFC completed a $1.0 billion unsecured public debt offering in the U.S. The notes, which are due in 2014, bear interest at 5.8 percent. The net proceeds of the offering were used to fund a portion of the acquisition of TBI.

After EnCana's acquisition of TBI, TBI and a subsidiary made a consent tender offer for $225 million for their 7.25 percent Senior Subordinated Notes. A total of 98.9 percent of the notes were tendered for a total cost of approximately $258 million. Subsequently, in December 2004 and January 2005, the balance of the notes were purchased for a total cost of approximately $2.9 million.

On August 4, 2004, EnCana completed a public offering in the United States for $250 million notes due in 2009 at 4.60 percent and $750 million notes due in 2034 at 6.50 percent. The proceeds from these issues were used primarily to repay existing bank and commercial paper indebtedness.

On August 9, 2004, EnCana redeemed all of its 8.50 percent Unsecured Junior Subordinated Debentures due 2048, which had an aggregate principal amount of C$200 million, at par plus accrued interest. On September 30, 2004, EnCana redeemed all of its 9.50 percent Preferred Securities due 2048, which had an aggregate principal amount of $150 million, at par.

In September 2004, EnCana filed a multi-jurisdictional shelf prospectus whereby it may issue from time to time up to $2 billion of debt securities. This shelf prospectus replaced EnCana's previous $2 billion U.S. debt shelf prospectus which expired on September 22, 2004. No amounts have been issued under the new shelf prospectus.

In October 2004, the Company completed the refinancing of its general corporate bank credit facilities. Under this refinancing, EnCana's core bank facilities were increased in size from C$4.0 billion to C$4.5 billion, and the term of the two tranches was extended to three and five years. In December, the bank credit facilities of a wholly owned US subsidiary were increased from $300 million to $600 million, all in a five year term.

As at December 31, 2004, the Company had available unused committed bank credit facilities in the amount of $2.4 billion.

In October 2004, EnCana received approval from the Toronto Stock Exchange ("TSX") to continue to purchase, for cancellation, Common Shares under a Normal Course Issuer Bid (the "Bid"). Under the Bid, EnCana was entitled to purchase for cancellation up to five percent of its Common Shares issued and outstanding on October 22, 2004 over a 12-month period ending October 28, 2005. As of December 31, 2004, EnCana had purchased for cancellation approximately 14.8 million of its shares under the Bid. In February 2005, EnCana received approval from the TSX to amend the Bid. Under the amended Bid, EnCana is entitled to purchase up to 46.1 million Common Shares (ten percent of the public float on October 22, 2004). Purchases may be made through the facilities of the TSX and the New York Stock Exchange, in accordance with the policies and rules of each exchange.

During 2004, EnCana purchased for cancellation a total of approximately 20 million shares for a total of approximately $1 billion under the terms of its Normal Course Issuer Bids.

***Normal Course Issuer Bid***
*(millions)*

| | Share Purchases | | | | Number of shares entitled to purchase |
|---|---|---|---|---|---|
| | **2004** | 2003 | 2002 | Total | |
| Bid expiring October 2003 | **–** | 20.2 | – | 20.2 | 23.8 |
| Bid expiring October 2004 | **5.5** | 3.6 | – | 9.1 | 23.2 |
| Bid expiring October 2005 | **14.8** | – | – | 14.8 | 46.1 |
| | **20.3** | 23.8 | – | 44.1 | |

## OUTSTANDING SHARE DATA

The Company is authorized to issue an unlimited number of Common Shares, an unlimited number of First Preferred Shares and an unlimited number of Second Preferred Shares. The reduction of 10.3 million Common Shares outstanding from the end of 2003 to the end of 2004 (18.3 million from the end of 2002 to the end of 2003) results from the repurchase of 20.3 million shares in 2004 (23.8 million in 2003) under the Normal Course Issuer Bid and the issuance of 9.7 million Common Shares (5.5 million in 2003) under Option plans.

*Share Capital – Common Shares*
*(millions)*

| | 2004 | 2003 | 2002 |
|---|---|---|---|
| Common shares outstanding, end of year | **450.3** | 460.6 | 478.9 |
| Weighted average common shares outstanding – diluted | **468.0** | 479.7 | 422.6 |

As at January 31, 2005, there were 446.5 million Common Shares outstanding. There were no Preferred Shares outstanding during these periods. Employees and directors have been granted options to purchase Common Shares under various plans. These plans and their terms and outstanding balances are disclosed in detail in Note 15 to the Consolidated Financial Statements.

Effective February 22, 2005 the Company's Board of Directors resolved to recommend the split of the Corporation's outstanding Common Shares on a two-for-one basis ("Share Split"). EnCana's shareholders will be asked to approve the Share Split at its annual and special meeting to be held on April 27, 2005. In addition to shareholder approval, the Share Split is subject to the receipt of all required regulatory approvals. If approved by shareholders, and subject to regulatory approvals, each shareholder will receive one additional common share for each common share he or she holds on the record date for the Share Split of May 12, 2005. Pursuant to the rules of the Toronto Stock Exchange, EnCana's common shares will commence trading on a subdivided basis at the opening of business on May 10, 2005, which is the second trading day preceding the record date. Also on May 10, 2005, EnCana's common shares listed on the New York Stock Exchange ("NYSE") will commence trading with rights entitling holders to an additional common share for each common share held upon the commencement of trading of the common shares on a subdivided basis on the NYSE. The trading of the common shares on a subdivided basis on the NYSE will occur one day after the delivery of share certificates to registered holders of EnCana's common shares. It is anticipated that share certificates representing the additional common shares resulting from the Share Split will be delivered to registered common shareholders on or about May 20, 2005.

The Compensation Committee of the Board of Directors, in 2003, approved a long-term incentive strategy for employees throughout EnCana which includes a significantly reduced level of stock option grants to be supplemented by grants of Performance Share Units ("PSUs"). In 2004, the Board of Directors approved a modification to the PSU plan that provides a reduced payout if relative ranking is below median. This change applies to units granted in both 2004 and 2005. PSUs will not result in the issue of Common Shares by the Company. Stock options granted in 2004 have an associated Tandem Share Appreciation Right ("TSAR") and employees may elect to exercise either the stock option or the associated TSAR. TSAR exercises will result in either cash payments by the Company or issuance of Common Shares.

As previously detailed in the "Liquidity and Capital Resources" section of this MD&A, the Company obtained regulatory approval under Canadian securities laws to purchase Common Shares under three consecutive Normal Course Issuer Bids which commenced in October 2002 and may continue until October 28, 2005. Under the terms of the bids, the Company repurchased for cancellation approximately 20 million Common Shares during 2004, and as of December 31, 2004, was entitled to purchase for cancellation an additional 8 million Common Shares. On February 4, 2005, EnCana received approval from the TSX to amend the Bid and increase the number of Common Shares available for purchase from five percent of the issued and outstanding shares on October 22, 2004 to ten percent of the public float. Under the amended Bid, EnCana is entitled to purchase for cancellation up to approximately 46.1 million Common Shares. To the date of the amendment, EnCana had purchased approximately 21.2 million Common Shares under the Bid, leaving approximately 24.9 million Common Shares available for purchase through the expiry of the Bid on October 28, 2005. Shareholders may obtain a copy of the Bid documents without charge at www.sedar.com or by contacting investor.relations@encana.com

## Contractual Obligations and Contingencies

The Company has entered into various commitments primarily related to debt, demand charges on firm transportation agreements, capital commitments and marketing agreements. The following table summarizes the Company's contractual obligations at December 31, 2004:

| | Expected Payment Date | | | | |
|---|---|---|---|---|---|
| *($ millions)* | 2005 | 2006 to 2007 | 2008 to 2009 | 2010+ | Total |
| Long-Term Debt | $ 188 | $ 487 | $ 841 | $ 4,434 | $ 5,950 |
| Asset Retirement Obligations | 2 | 13 | – | 3,680 | 3,695 |
| Operating Leases (2) | 42 | 84 | 65 | 152 | 343 |
| Pipeline Transportation | 297 | 499 | 402 | 1,010 | 2,208 |
| Capital Commitments | 190 | 63 | 4 | 38 | 295 |
| Purchase of Goods and Services | 121 | 37 | 12 | 5 | 175 |
| Product Purchases | 171 | 57 | 48 | 134 | 410 |
| | 1,011 | 1,240 | 1,372 | 9,453 | 13,076 |
| Discontinued operations (3) | 99 | 185 | 189 | 876 | 1,349 |
| Total Contractual Obligations (1) | $ 1,110 | $ 1,425 | $ 1,561 | $ 10,329 | $ 14,425 |

*(1) In addition, the Company has made commitments related to its risk management program. See Note 17 to the Consolidated Financial Statements. The Company also has an obligation to fund its Pension Plan and Other Post Retirement Benefits as disclosed in Note 16 to the Consolidated Financial Statements.*
*(2) Related to office space.*
*(3) Primarily related to long-term transportation commitments.*

In addition to the long-term debt payments outlined above, at December 31, 2004 the Company had $1,914 million outstanding related to Banker's Acceptances, Commercial Paper and LIBOR loans that are supported by revolving credit facilities and term loan borrowings. The Company intends and expects that it will have the ability to extend the term of this debt on an ongoing basis. Further details regarding the Company's long-term debt are described in Note 13 to the Consolidated Financial Statements.

Additional disclosure regarding the contractual obligations outlined above is included in Note 19 to the Consolidated Financial Statements.

As at December 31, 2004, EnCana had remained a party to long-term, fixed price, physical contracts with a current delivery of approximately 48 MMcf/d with varying terms and volumes through 2017. The total volume to be delivered within the terms of these contracts is 167 Bcf at a weighted average price of $3.71 per Mcf. At December 31, 2004, these transactions had an unrealized loss of $157 million.

Commitments and Contingencies associated with Ecuador discontinued operations are included in Note 5 to EnCana's Consolidated Financial Statements.

### Variable Interest Entities ("VIE")

In December 2004, an EnCana subsidiary finalized the purchase of certain oil and gas properties in Texas for approximately $251 million. The purchase was facilitated by an unrelated party, which holds the assets in trust for the Company. EnCana operates the properties, receives all the revenue and pays all of the expenses associated with these properties. The assets will be transferred to EnCana at the earliest of June 15, 2005 or upon the disposition of certain natural gas and crude oil properties by EnCana. EnCana has determined that this relationship represents an interest in a VIE and that EnCana is the primary beneficiary of the VIE. EnCana has included these properties in its consolidated results from the date of acquisition. This subsidiary will not hold title to these properties until an exchange transaction has been completed.

### Off-Balance Sheet Arrangements

The Company does not have any off-balance sheet arrangements that have or are reasonably likely to have an effect on its results of operations or financial condition.

### Leases

As a normal course of business, the Company leases office space for personnel who support field operations and corporate purposes.

### Legal Proceedings Related to Discontinued Merchant Energy Operations

In July 2003, the Company's indirect wholly owned U.S. marketing subsidiary, WD Energy Services Inc. ("WD"), concluded a settlement with the U.S. Commodity Futures Trading Commission ("CFTC") of a previously disclosed CFTC investigation. The investigation related to alleged inaccurate reporting of natural gas trading information during 2000 and 2001 by former employees of WD's now discontinued Houston-based merchant energy trading operation to energy industry publications that compiled and reported index prices. All Houston-based merchant energy trading operations were discontinued following the merger with AEC in 2002. Under the terms of the settlement, WD agreed to pay a civil monetary penalty in the amount of $20 million without admitting or denying the findings in the CFTC's order.

The Company and WD are defendants in a lawsuit filed by E. & J. Gallo Winery in the United States District Court in California and, along with other energy companies, are defendants in several other lawsuits in California (many of which are class actions) and three class action lawsuits filed in the United States District Court in New York. A motion by the Company and WD to dismiss the Gallo complaint on the basis that the Federal Energy Regulatory Commission had exclusive jurisdiction regarding this matter was not granted. The Gallo complaint claims damages in excess of $30 million, before potential trebling under California laws.

Most of the California lawsuits were transferred by the Judicial Panel on Multidistrict Litigation on a consolidated basis to the Nevada District Court and all of the New York lawsuits were consolidated in New York District Court by the plaintiff's application. The Nevada District Court has remanded the California State Court cases back to the California State Court for hearing. The California lawsuits relate to sales of natural gas in California from 1999 to the present and contain allegations that the defendants engaged in a conspiracy with unnamed competitors in the natural gas and derivatives market in California in violation of U.S. and California anti-trust and unfair competition laws to artificially raise the price of natural gas through various means including the illegal sharing of price information through online trading, price indices and wash trading. The New York lawsuits claim that the defendants' alleged manipulation of natural gas price indices resulted in higher prices of natural gas futures and option contracts traded on the NYMEX from 2000 to 2002. EnCana Corporation has been dismissed from the New York lawsuits, leaving WD and several other companies unrelated to the Company as the remaining defendants. As is customary, the class actions do not specify the amount of damages claimed.

The Company and WD intend to vigorously defend against these claims; however, the Company cannot predict the outcome of these proceedings or any future proceedings against the Company, whether these proceedings would lead to monetary damages which could have a material adverse effect on the Company's financial position, or whether there will be other proceedings arising out of these allegations.

## Accounting Policies and Estimates

### Changes in Accounting Principles and Practices

#### Hedging Relationships

On January 1, 2004, the Company adopted the amendments made to the Canadian Institute of Chartered Accountants ("CICA") Accounting Guideline AcG-13 "Hedging Relationships". Derivative instruments outstanding at January 1, 2004 that did not qualify as a hedge under AcG-13 or were not designated as a hedge, were recorded using the mark-to-market accounting method whereby their fair value was recorded on the Consolidated Balance Sheet. The impact on the Company's Consolidated Financial Statements at January 1, 2004 was an increase in assets of $145 million, an increase in liabilities of $380 million and a net deferred loss of $235 million. These amounts are taken into net earnings as the contracts expire. At December 31, 2004, there remains a net gain of $72 million to be recognized as described in Note 2 to the Consolidated Financial Statements.

### Consolidation of Variable Interest Entities

On November 1, 2004, the Company retroactively adopted the new CICA Accounting Guideline AcG-15 "Consolidation of Variable Interest Entities". AcG-15 defines a variable interest entity ("VIE") as a legal entity in which either the total equity at risk is not sufficient to permit the entity to finance its activities without additional subordinated financial support provided by other parties or the equity owners lack a controlling financial interest. The guideline requires the enterprise which absorbs the majority of a VIE's expected gains or losses, the primary beneficiary, to consolidate the VIE.

The retroactive adoption of AcG-15 had no effect on EnCana's prior Consolidated Financial Statements.

## CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Management is required to make judgments, assumptions and estimates in the application of generally accepted accounting principles that have a significant impact on the financial results of the Company. The following discussion outlines the accounting policies and practices that are critical to determining EnCana's financial results.

### Full Cost Accounting

EnCana follows the CICA guideline on full cost accounting in the oil and gas industry to account for oil and gas properties. Under this method, all costs directly associated with the acquisition of, exploration for, and the development of natural gas and crude oil reserves are capitalized on a country-by-country cost centre basis and costs associated with production are expensed. The capitalized costs are depreciated, depleted and amortized using the unit-of-production method based on estimated proved reserves. Reserve estimates can have a significant impact on earnings, as they are a key component in the calculation of DD&A. A downward revision in a reserve estimate could result in a higher DD&A charge to earnings. In addition, if net capitalized costs are determined to be in excess of the calculated ceiling, which is based largely on reserve estimates (see asset impairment discussion below), the excess must be written off as an expense charged against earnings. In the event of a property disposition, proceeds are normally deducted from the full cost pool without recognition of a gain or loss unless there is a change in the DD&A rate of 20 percent or greater.

### Oil and Gas Reserves

All of EnCana's oil and gas reserves are evaluated and reported on by independent qualified reserve evaluators. The estimation of reserves is a subjective process. Forecasts are based on engineering data, projected future rates of production, estimated commodity price forecasts and the timing of future expenditures, all of which are subject to numerous uncertainties and various interpretations. Reserve estimates can be revised upward or downward based on the results of future drilling, testing, production levels and economics of recovery based on cash flow forecasts.

### Asset Impairments

Under full cost accounting, a ceiling test is performed to ensure that unamortized capitalized costs in each cost centre do not exceed their fair value. An impairment loss is recognized in net earnings when the carrying amount of a cost centre is not recoverable and the carrying amount of the cost centre exceeds its fair value. The carrying amount of the cost centre is not recoverable if the carrying amount exceeds the sum of the undiscounted cash flows from proved reserves. If the sum of the cash flows is less than carrying amount, the impairment loss is limited to an amount by which the carrying amount exceeds the sum of:

i) the fair value of proved and probable reserves; and

ii) the costs of unproved properties that have been subject to a separate impairment test.

### Asset Retirement Obligations

The fair value of estimated asset retirement obligations is recognized in the Consolidated Balance Sheet when identified and a reasonable estimate of fair value can be made. Asset retirement obligations include those legal obligations where the Company will be required to retire tangible long-lived assets such as producing well sites, offshore production platforms and natural gas processing plants. These obligations also include items for which the Company has made promissory estoppel. The asset retirement cost, equal to the initially estimated fair value of the asset retirement obligation, is capitalized as part of the cost of the related long-lived asset. Increases in the asset retirement obligation resulting from the passage of time are recorded as accretion of asset retirement obligation in the Consolidated Statement of Earnings. Amounts recorded for asset retirement obligations are based on estimates of reserves and on retirement costs which will not be incurred for several years. Actual payments to settle the obligations may differ from estimated amounts.

### Goodwill

Goodwill, which represents the excess of purchase price over fair value of net assets acquired in the merger with AEC and the acquisition of TBI, is assessed by the Company for impairment at least annually. Goodwill was allocated to the business segments at the time of the above transactions based on their respective book values compared to fair values. If it is determined that the fair value of the assets and liabilities of the business segment is less than the book value of the business segment at the time of assessment, an impairment amount is determined by deducting the fair value from the book value and applying it against the book balance of goodwill. The offset is charged to the Consolidated Statement of Earnings as additional DD&A.

### Derivative Financial Instruments

Derivative financial instruments are used by the Company to manage its exposure to market risks relating to commodity prices, foreign currency exchange rates and interest rates. The Company's policy is not to utilize derivative financial instruments for speculative purposes.

The Company enters into financial transactions to reduce its exposure to price fluctuations with respect to a portion of its oil and gas production to help achieve returns on new projects, targeted returns on new investments and steady funding of growth projects or to mitigate market price risk associated with cash flows expected to be generated from budgeted capital programs. These transactions generally are swaps, collars or options and are generally entered into with major financial institutions or commodities trading institutions.

The Company may also utilize derivative financial instruments such as interest rate swap agreements to manage the fixed and floating interest rate mix of the Company's total debt portfolio and related overall cost of borrowing. The interest rate swap agreements involve the periodic exchange of payments, without the exchange of the normal principal amount upon which the payments are based, and are recorded as an adjustment of interest expense on the hedged debt instrument.

The Company may enter into hedges of its foreign currency exposures on foreign currency denominated long-term debt by entering into offsetting forward exchange contracts. Foreign exchange translation gains and losses on these instruments are accrued under other current, or non-current, assets or liabilities on the balance sheet and recognized in foreign exchange in the period to which they relate, offsetting the respective translation losses and gains recognized on the underlying foreign currency long-term debt. Premiums or discounts on these forward instruments are amortized as an adjustment of interest expense over the term of the contract.

The Company also purchases foreign exchange forward contracts to hedge anticipated sales to customers in the United States. Foreign exchange translation gains and losses on these instruments are recognized as an adjustment of the revenues when the sale is recorded.

Derivative instruments that do not qualify as hedges, or are not designated as hedges, are recorded using the mark-to-market method of accounting whereby instruments are recorded in the Consolidated Balance Sheet as either an asset or liability with changes in fair value recognized in net earnings. Realized gains or losses from financial derivatives are recognized in natural gas and crude oil revenues as the related production occurs. Unrealized gains and losses are recognized in revenues at the end of each respective reporting period. The estimate of fair value of all derivative instruments is based on quoted market prices or, in their absence, third party market indicators.

In 2004, the Company elected not to designate any of its current price risk management activities as accounting hedges under AcG-13 and accordingly, accounts for all derivatives using the mark-to-market accounting method.

### Pensions and Other Post Retirement Benefits

The Company accrues for its obligations under its employee benefit plans and the related costs, net of plan assets.

The cost of pensions and other retirement benefits is actuarially determined using the projected benefit method based on length of service, and reflects Management's best estimate of expected plan investment performance, salary escalation, retirement ages of employees and expected future health care costs. The expected return on plan assets is based on the fair value of those assets. The obligation is discounted using a market interest rate at the beginning of the year on high quality corporate debt instruments.

Pension expense includes the cost of pension benefits earned during the current year, the interest cost on pension obligations, the expected return on pension plan assets, the amortization of the net transitional obligation, the amortization of adjustments arising from pension plan amendments and the amortization of the excess of the net actuarial gain or loss over ten percent of the greater of the benefit obligation and the fair value of plan assets. The amortization period covers the expected average remaining services lives of employees covered by the plans.

Pension expense for the defined contribution pension plans is recorded as the benefits are earned by the employees covered by the plan.

Pension costs are a component of compensation costs.

### Performance Share Units ("PSUs")

The PSU plans provide for a range of payouts, based on EnCana's performance relative to certain peers.

The Company expenses the cost of PSUs based on expected payouts, however, the amounts to be paid, if any, may vary from the current estimate.

## RISK MANAGEMENT

EnCana's results are affected by

- financial risks (including commodity price, foreign exchange, interest rate and credit risks)
- operational risks
- environmental, health, safety and security risks
- reputational risks

### FINANCIAL RISKS

The Company partially mitigates its exposure to financial risks through the use of various financial instruments and physical contracts. The use of derivative instruments is governed under formal policies approved by senior management, and is subject to limits established by the Board of Directors. As a means of mitigating exposure to commodity price risk, the Company has entered into various financial instrument agreements. The Company's policy is not to use derivative financial instruments for speculative purposes. The details of these instruments, including any unrealized gains or losses as of December 31, 2004 are disclosed in Note 17 to the Consolidated Financial Statements.

The Company has in place policies and procedures with respect to the required documentation and approvals for the use of derivative financial instruments and specifically ties their use, in the case of commodities, to the mitigation of price risk associated with cash flows expected to be generated from budgeted capital programs and in other cases to the mitigation of price risks for specific assets and obligations.

With respect to transactions involving proprietary production or assets, the financial instruments generally used by the Company are swaps, collars or options which are entered into with major financial institutions, integrated energy companies or commodities trading institutions.

### Commodity Price

To partially mitigate the natural gas commodity price risk, the Company entered into swaps which fix the AECO and NYMEX prices and collars and put options which fix the range of AECO and NYMEX prices. To help protect against widening natural gas price differentials in various production areas, the Company has entered into swaps to fix the AECO and Rockies price differential from the NYMEX price. Physical contracts relating to these activities had an unrecognized loss of $9 million.

The Company has also entered into contracts to purchase and sell natural gas as part of its daily ongoing operations of the Company's proprietary production management. Physical contracts associated with this activity had an unrecognized gain of $43 million.

As part of its gas storage optimization program, EnCana has entered into financial instruments and physical contracts at various locations and terms over the next 15 months to partially manage the price volatility of the corresponding physical transactions and inventories. The financial instruments used include futures, fixed for floating swaps and basis swaps.

For crude oil price risk, the Company has partially mitigated its exposure to the WTI NYMEX price for a portion of its oil production with fixed price swaps, three-way put spreads and put options.

The Company has a power purchase arrangement contract that expires in 2005. This contract was entered into as part of a cost management strategy.

### Foreign Exchange

As a means of mitigating the exposure to fluctuations in the U.S. to Canadian exchange rate, the Company may enter into foreign exchange contracts. The Company also enters into foreign exchange contracts in conjunction with crude oil marketing transactions. Gains or losses on these contracts are recognized when the difference between the average month spot rate and the rate on the date of settlement is determined.

The Company also maintains a mix of both U.S. dollar and Canadian dollar debt which helps to offset the exposure to the fluctuations in the U.S./Canadian dollar exchange rate. In addition to direct issuance of U.S. dollar denominated debt, the Company has entered into cross currency swaps on a portion of its debt as a means of managing the U.S./Canadian dollar debt mix.

### Interest Rates

The Company partially mitigates its exposure to interest rate changes by maintaining a mix of both fixed and floating rate debt. The Company has entered into interest rate swap transactions from time to time as a means of managing the fixed/floating rate debt portfolio mix.

### Credit Risk

The Company is exposed to credit related losses in the event of default by counterparties. The Company does not expect any counterparties to fail to meet their obligations because of credit practices that are in place that limit transactions to counterparties of investment grade credit quality. A substantial portion of the Company's accounts receivable is with customers in the oil and gas industry. Credit losses on the accounts receivable may arise as a result of non-performance by customers on their contractual obligations. To manage the Company's exposure to credit losses, Board-approved credit policies govern the Company's credit portfolio.

## OPERATIONAL RISK

EnCana mitigates operational risk through a number of policies and processes. As part of the capital approval process, the Company's projects are evaluated on a fully risked basis, including geological risk and engineering risk. In addition, the asset teams undertake a process called Lookback and Learning. In this process, each asset team undertakes a thorough review of their previous capital program to identify key learnings, which often includes operational issues that positively and negatively impacted the project's results. Mitigation plans are developed for the operational issues which had a negative impact on results. These mitigation plans are then incorporated into the current year plan for the project. On an annual basis, these Lookback results are analyzed for the Company's capital program with the results and identified learnings shared across the Company.

All projects include a Business Risk Burden that is intended to account for the unforeseen risks. The amount of Business Risk Burden that is used on a particular project depends on the project's history of Lookback results and the type of expenditure.

A peer review process is used to ensure that capital projects are appropriately risked and that knowledge is shared across the Company. Peer reviews are undertaken primarily for exploration projects and early stage resource plays, although they may occur for any type of project.

The Company also partially mitigates operational risks by maintaining a comprehensive insurance program.

### Environment, Health, Safety and Security Risk

These risks are managed by executing policies and standards that comply with or exceed government regulations and industry standards. In addition, the Company maintains a system that identifies, assesses and controls safety and environmental risk and requires regular reporting to senior management and the Board of Directors. The Corporate Responsibility, Environment, Health & Safety Committee of EnCana's Board of Directors approves environmental policy and oversees compliance with government laws and regulations. Monitoring and reporting programs for environmental, health and safety performance in day-to-day operations, as well as inspections and assessments, are designed to provide assurance that environmental and regulatory standards are met. Contingency plans are in place for a timely response to an environmental event and remediation/reclamation strategies are utilized to restore the environment.

Security risks are managed through a Security Program designed to ensure that EnCana's personnel and assets are protected. EnCana has also established an Investigations Committee with the mandate to address potential violations of Company policies and practices.

#### Kyoto Protocol

The Kyoto protocol, ratified by the Canadian Federal Government in December 2002, came into force on February 16, 2005. The protocol commits Canada to reducing greenhouse gas emissions to six percent below 1990 levels over the period 2008 – 2012. It is expected that the Federal Government will make a substantive announcement outlining its Climate Change action plan coinciding with Kyoto coming into force. The Climate Change Working Group of Canadian Association of Petroleum Producers is working with the Federal and Alberta governments to develop an approach for implementing targets and enabling greenhouse gas control legislation which protects the industry's competitiveness, limits the cost and administrative burden of compliance and supports continued investment in the sector.

As the federal government has yet to release its Kyoto compliance plan, EnCana is unable to predict the impact of the potential regulations upon its business; however, it is possible that the Company would face increases in operating costs in order to comply with greenhouse gas emissions legislation.

### Reputational Risk

EnCana takes a pro-active approach to the identification and management of issues that affect the Company's reputation and has established consistent and clear procedures, guidelines and responsibility for identifying and managing these issues. Issues affecting or with the potential to affect EnCana's reputation are generally either emerging issues that can be identified early and then managed or unforeseen issues that arise unexpectedly and must be managed on an urgent basis.

## OUTLOOK

| *Volume Outlook for Continuing Operations* | 2005 Guidance (2) | 2004 Actual | Increase in 2005 (3) |
|---|---|---|---|
| Produced Gas Sales *(MMcf per day)* | | | |
| Canada | 2,200 - 2,300 | 2,099 | 7% |
| United States | 1,150 - 1,200 | 869 | 35% |
| Total Produced Gas Sales | 3,350 - 3,500 | 2,968 | 15% |
| Crude Oil and NGLs *(Mbbls per day)* | | | |
| Canada | 135 - 155 | 154 | -6% |
| United States | 12 - 14 | 12 | 8% |
| Total Crude Oil and NGLs | 150 - 170 | 166 | -4% |
| Total *(MMcfe per day)* (1) | 4,250 - 4,500 | 3,966 | 10% |

*(1) Liquids converted to thousand cubic feet equivalent at 1 barrel = 6 thousand cubic feet.*
*(2) Guidance released February 23, 2005.*
*(3) Using mid-point of guidance.*

*2005 Capital Investment for Continuing Operations*
*($ billions)*

| | |
|---|---|
| Upstream | $4.5 - $4.8 |
| Midstream & Marketing and Corporate | 0.4 - 0.4 |
| Core Capital | $4.9 - $5.2 |

EnCana plans to continue to focus principally on growing natural gas production and storage capacity in North America. The Company will also continue to invest in in situ oilsands development.

Strong storage injection requirements combined with reduced U.S. and Canadian supply have tightened the balance between supply and demand resulting in higher average natural gas prices in 2004. The outlook for 2005 and beyond will be principally impacted by weather, timing of new supplies and economic activity.

Volatility in crude oil prices is expected to continue in 2005 as a result of market uncertainties over continued demand growth in China, the reliability of production from key producing countries, and OPEC success at managing prices and the overall state of the world economies.

The Company expects its 2005 core capital investment program, of between $4.9 billion and $5.2 billion, to be funded from cash flow.

EnCana's results are affected by external market factors, such as fluctuations in the prices of crude oil and natural gas, as well as movements in foreign currency exchange rates. The following tables provide projected estimates for 2005 of the sensitivity of the Company's 2005 net earnings and cash flow to changes in commodity prices and the U.S./Canadian dollar exchange rate.

| *Sensitivity of 2005 Net Earnings from Continuing Operations and Cash Flow from Continuing Operations (Including Hedges)* (1)(2) *($ millions)* | Net Earnings from Continuing Operations | Cash Flow from Continuing Operations |
|---|---|---|
| $0.25 per million British thermal units increase in the NYMEX gas price | $ 95 | $ 135 |
| $1.00 per barrel increase in the WTI oil price | 15 | 15 |
| $0.01 decrease in the U.S./Canadian dollar exchange rate | (20) | 5 |

*(1) Hedge position as at December 31, 2004.*
*(2) Based on forward curve commodity price and forward curve estimates dated December 31, 2004.*

| *Sensitivity of 2005 Net Earnings from Continuing Operations and Cash Flow from Continuing Operations (Excluding Hedges)* (1) *($ millions)* | Net Earnings from Continuing Operations | Cash Flow from Continuing Operations |
|---|---|---|
| $0.25 per million British thermal units increase in the NYMEX gas price | $ 185 | $ 185 |
| $1.00 per barrel increase in the WTI oil price | 25 | 25 |
| $0.01 decrease in the U.S./Canadian dollar exchange rate | (20) | 5 |

*(1) Based on forward curve commodity price and forward curve estimates dated December 31, 2004.*

These estimates are based on management's assumptions utilized for 2005 planning purposes, as discussed in this section. Assumptions include certain levels and profiles of capital expenditures, projected asset disposals, operating costs, projected sales volumes, tax rates, interest rates, foreign currency exchange rates, inflation rates and other assumptions that impact operations. These assumptions can vary significantly from actual events and may result in material variances from the expected results.

In determining the current income tax expense deducted in arriving at these estimates, management has assumed a combined marginal tax rate of approximately 37 percent. This tax rate is itself affected in varying degrees by the assumptions referred to in the preceding paragraph.

## MANAGEMENT REPORT

The accompanying Consolidated Financial Statements of EnCana Corporation are the responsibility of Management. The financial statements have been prepared by Management in United States dollars in accordance with Canadian Generally Accepted Accounting Principles and include certain estimates that reflect Management's best judgments. Financial information contained throughout the annual report is consistent with these financial statements.

Management has overall responsibility for internal controls and has developed and maintains an extensive system of internal controls that provides reasonable assurance that all transactions are accurately recorded, that the financial statements realistically report the Company's operating and financial results and that the Company's assets are safeguarded. The Company's Internal Audit department reviews and evaluates the adequacy of and compliance with the Company's internal controls. The policy of the Company is to maintain the highest standard of ethics in all its activities and it has a written business conduct and ethics practice.

The Company's Board of Directors has approved the information contained in the financial statements. The Board of Directors fulfills its responsibility regarding the financial statements mainly through its Audit Committee, which has a written mandate that complies with the current requirements of the United States Sarbanes-Oxley Act of 2002 and voluntarily complies, in principle, with the Audit Committee guidelines of the New York Stock Exchange and the Toronto Stock Exchange. The Audit Committee meets at least on a quarterly basis.

PricewaterhouseCoopers LLP, an independent firm of chartered accountants, was appointed by a vote of shareholders at the Company's last annual meeting to audit the Consolidated Financial Statements and provide an independent opinion.

Gwyn Morgan
President &
Chief Executive Officer

John D. Watson
Executive Vice-President &
Chief Financial Officer

February 7, 2005

## AUDITORS' REPORT

TO THE SHAREHOLDERS OF ENCANA CORPORATION

We have audited the Consolidated Balance Sheets of EnCana Corporation as at December 31, 2004 and December 31, 2003 and the Consolidated Statements of Earnings, Retained Earnings and Cash Flows for each of the years in the three-year period ended December 31, 2004. These financial statements are the responsibility of the Company's Management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by Management, as well as evaluating the overall financial statement presentation.

In our opinion, these Consolidated Financial Statements present fairly, in all material respects, the financial position of the Company as at December 31, 2004 and December 31, 2003 and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2004 in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Chartered Accountants
Calgary, Alberta
Canada

February 7, 2005

COMMENTS BY AUDITOR FOR U.S. READERS ON CANADA-U.S. REPORTING DIFFERENCES

In the United States, reporting standards for auditors require the addition of an explanatory paragraph (following the opinion paragraph) when there is a change in accounting principles that has a material effect on the comparability of the Company's financial statements, such as the changes described in Note 2 to the Consolidated Financial Statements. Our report to the shareholders dated February 7, 2005 is expressed in accordance with Canadian reporting standards which do not require a reference to such a change in accounting principles in the Auditors' report when the change is properly accounted for and adequately disclosed in the financial statements.

PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Chartered Accountants
Calgary, Alberta
Canada

February 7, 2005

## CONSOLIDATED STATEMENT OF EARNINGS

| *For the years ended December 31 ($ millions, except per share amounts)* | | 2004 | 2003 | 2002 |
|---|---|---|---|---|
| REVENUES, NET OF ROYALTIES | *(Note 4)* | | | |
| Upstream | | $ 7,256 | $ 5,797 | $ 3,326 |
| Midstream & Market Optimization | | 4,749 | 3,887 | 2,594 |
| Corporate | | (195) | 2 | 8 |
| | | 11,810 | 9,686 | 5,928 |
| EXPENSES | *(Note 4)* | | | |
| Production and mineral taxes | | 311 | 164 | 105 |
| Transportation and selling | | 499 | 484 | 332 |
| Operating | | 1,350 | 1,196 | 749 |
| Purchased product | | 4,276 | 3,455 | 2,200 |
| Depreciation, depletion and amortization | | 2,402 | 1,989 | 1,186 |
| Administrative | | 197 | 173 | 118 |
| Interest, net | *(Note 7)* | 397 | 283 | 286 |
| Accretion of asset retirement obligation | *(Note 14)* | 22 | 17 | 13 |
| Foreign exchange gain | *(Note 8)* | (417) | (598) | (11) |
| Stock-based compensation | | 17 | 18 | – |
| Gain on dispositions | *(Note 6)* | (113) | (1) | (33) |
| | | 8,941 | 7,180 | 4,945 |
| NET EARNINGS BEFORE INCOME TAX | | 2,869 | 2,506 | 983 |
| Income tax expense | *(Note 9)* | 658 | 364 | 317 |
| NET EARNINGS FROM CONTINUING OPERATIONS | | 2,211 | 2,142 | 666 |
| NET EARNINGS FROM DISCONTINUED OPERATIONS | *(Note 5)* | 1,302 | 218 | 146 |
| NET EARNINGS | | $ 3,513 | $ 2,360 | $ 812 |
| NET EARNINGS FROM CONTINUING OPERATIONS PER COMMON SHARE | *(Note 18)* | | | |
| Basic | | $ 4.80 | $ 4.52 | $ 1.59 |
| Diluted | | $ 4.72 | $ 4.47 | $ 1.58 |
| NET EARNINGS PER COMMON SHARE | *(Note 18)* | | | |
| Basic | | $ 7.63 | $ 4.98 | $ 1.94 |
| Diluted | | $ 7.51 | $ 4.92 | $ 1.92 |

## CONSOLIDATED STATEMENT OF RETAINED EARNINGS

| *For the years ended December 31 ($ millions)* | | 2004 | 2003 | 2002 |
|---|---|---|---|---|
| RETAINED EARNINGS, BEGINNING OF YEAR | | $ 5,276 | $ 3,523 | $ 2,819 |
| Net Earnings | | 3,513 | 2,360 | 812 |
| Dividends on Common Shares | | (183) | (139) | (108) |
| Charges for Normal Course Issuer Bid | *(Note 15)* | (671) | (468) | – |
| RETAINED EARNINGS, END OF YEAR | | $ 7,935 | $ 5,276 | $ 3,523 |

*See accompanying notes to Consolidated Financial Statements.*

## CONSOLIDATED BALANCE SHEET

| As at December 31 ($ millions) | | 2004 | 2003 |
|---|---|---|---|
| ASSETS | | | |
| Current Assets | | | |
| Cash and cash equivalents | | $ 602 | $ 113 |
| Accounts receivable and accrued revenues | | 1,898 | 1,165 |
| Risk management | (Notes 2, 17) | 336 | – |
| Inventories | (Note 10) | 513 | 557 |
| Assets of discontinued operations | (Note 5) | 156 | 781 |
| | | 3,505 | 2,616 |
| Property, Plant and Equipment, net | (Notes 4, 11) | 23,140 | 17,770 |
| Investments and Other Assets | (Note 12) | 334 | 268 |
| Risk Management | (Notes 2, 17) | 87 | – |
| Assets of Discontinued Operations | (Note 5) | 1,623 | 1,545 |
| Goodwill | | 2,524 | 1,911 |
| | (Note 4) | $ 31,213 | $ 24,110 |
| LIABILITIES AND SHAREHOLDERS' EQUITY | | | |
| Current Liabilities | | | |
| Accounts payable and accrued liabilities | | $ 1,879 | $ 1,348 |
| Income tax payable | | 359 | 32 |
| Risk management | (Notes 2, 17) | 241 | – |
| Liabilities of discontinued operations | (Note 5) | 280 | 405 |
| Current portion of long-term debt | (Note 13) | 188 | 287 |
| | | 2,947 | 2,072 |
| Long-Term Debt | (Note 13) | 7,742 | 6,088 |
| Other Liabilities | | 118 | 21 |
| Risk Management | (Notes 2, 17) | 192 | – |
| Asset Retirement Obligation | (Note 14) | 611 | 383 |
| Liabilities of Discontinued Operations | (Note 5) | 102 | 112 |
| Future Income Taxes | (Note 9) | 5,193 | 4,156 |
| | | 16,905 | 12,832 |
| Commitments and Contingencies | (Note 19) | | |
| Shareholders' Equity | | | |
| Share capital | (Note 15) | 5,299 | 5,305 |
| Share options, net | | 10 | 55 |
| Paid in surplus | | 28 | 18 |
| Retained earnings | | 7,935 | 5,276 |
| Foreign currency translation adjustment | | 1,036 | 624 |
| | | 14,308 | 11,278 |
| | | $ 31,213 | $ 24,110 |

*See accompanying notes to Consolidated Financial Statements.*

Approved by the Board

David P. O'Brien
*Director*

Barry W. Harrison
*Director*

## CONSOLIDATED STATEMENT OF CASH FLOWS

| For the years ended December 31 ($ millions) | | 2004 | 2003 | 2002 |
|---|---|---|---|---|
| **OPERATING ACTIVITIES** | | | | |
| Net earnings from continuing operations | | $ 2,211 | $ 2,142 | $ 666 |
| Depreciation, depletion and amortization | | 2,402 | 1,989 | 1,186 |
| Future income taxes | *(Note 9)* | 91 | 477 | 383 |
| Unrealized loss on risk management | *(Note 17)* | 190 | – | – |
| Unrealized foreign exchange gain | *(Note 8)* | (285) | (545) | (23) |
| Accretion of asset retirement obligation | *(Note 14)* | 22 | 17 | 13 |
| Gain on dispositions | *(Note 6)* | (113) | (1) | (33) |
| Other | | 87 | 56 | (133) |
| Cash flow from continuing operations | | 4,605 | 4,135 | 2,059 |
| Cash flow from discontinued operations | | 375 | 324 | 360 |
| Cash flow | | 4,980 | 4,459 | 2,419 |
| Net change in other assets and liabilities | | (176) | (84) | (17) |
| Net change in non-cash working capital from continuing operations | *(Note 18)* | 1,455 | (568) | (889) |
| Net change in non-cash working capital from discontinued operations | | (1,668) | 497 | 104 |
| | | 4,591 | 4,304 | 1,617 |
| **INVESTING ACTIVITIES** | | | | |
| Business combinations | *(Note 3)* | (2,335) | – | (80) |
| Capital expenditures | *(Note 4)* | (4,817) | (4,627) | (2,771) |
| Proceeds on disposal of assets | *(Note 4)* | 1,144 | 301 | 363 |
| Dispositions (acquisitions) | *(Note 6)* | 386 | (91) | 60 |
| Equity investments | | 47 | (6) | – |
| Net change in investments and other | | 45 | (15) | 39 |
| Net change in non-cash working capital from continuing operations | *(Note 18)* | (21) | (113) | 195 |
| Discontinued operations | | 1,292 | 822 | (401) |
| | | (4,259) | (3,729) | (2,595) |
| **FINANCING ACTIVITIES** | | | | |
| Net issuance of revolving long-term debt | | 72 | 288 | – |
| Issuance of long-term debt | | 3,761 | 500 | 1,506 |
| Repayment of long-term debt | | (2,759) | (142) | (1,206) |
| Issuance of common shares | *(Note 15)* | 281 | 114 | 88 |
| Purchase of common shares | *(Note 15)* | (1,004) | (868) | – |
| Dividends on common shares | | (183) | (139) | (108) |
| Other | | (5) | (13) | (54) |
| Discontinued operations | | – | (282) | 272 |
| | | 163 | (542) | 498 |
| **DEDUCT: FOREIGN EXCHANGE LOSS (GAIN) ON CASH AND CASH EQUIVALENTS HELD IN FOREIGN CURRENCY** | | 6 | 10 | (2) |
| **INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS** | | 489 | 23 | (478) |
| **CASH AND CASH EQUIVALENTS, BEGINNING OF YEAR** | | 113 | 90 | 568 |
| **CASH AND CASH EQUIVALENTS, END OF YEAR** | | $ 602 | $ 113 | $ 90 |
| Supplemental Cash Flow Information | *(Note 18)* | | | |

*See accompanying notes to Consolidated Financial Statements.*

# NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

*For the year ended December 31, 2004*

Prepared using Canadian Generally Accepted Accounting Principles.
All amounts in US$ millions, unless otherwise indicated.

## 1 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

In these Consolidated Financial Statements, unless otherwise indicated, all dollar amounts are expressed in United States (U.S.) dollars. EnCana has adopted the U.S. dollar as its reporting currency since most of its revenue is closely tied to the U.S. dollar and to facilitate a more direct comparison to other North American upstream exploration and development companies. All references to US$ or to $ are to United States dollars and references to C$ are to Canadian dollars.

EnCana is in the business of exploration for, production and marketing of natural gas, crude oil and natural gas liquids, as well as natural gas storage, natural gas liquids processing and power generation operations.

### A) Principles of Consolidation

The Consolidated Financial Statements include the accounts of EnCana Corporation and its subsidiaries ("EnCana" or the "Company") and are presented in accordance with Canadian generally accepted accounting principles. Information prepared in accordance with generally accepted accounting principles in the United States is included in Note 20.

Investments in jointly controlled companies, jointly controlled partnerships (collectively called "affiliates") and unincorporated joint ventures are accounted for using the proportionate consolidation method, whereby EnCana's proportionate share of revenues, expenses, assets and liabilities are included in the accounts.

Investments in companies and partnerships in which EnCana does not have direct or joint control over the strategic operating, investing and financing decisions, but does have significant influence on them, are accounted for using the equity method.

### B) Foreign Currency Translation

The accounts of self-sustaining operations are translated using the current rate method, whereby assets and liabilities are translated at period-end exchange rates, while revenues and expenses are translated using average rates over the period. Translation gains and losses relating to the self-sustaining operations are included as a separate component of shareholders' equity.

Monetary assets and liabilities of the Company that are denominated in foreign currencies are translated into its functional currency at the rates of exchange in effect at the period end date. Any gains or losses are recorded in the Consolidated Statement of Earnings.

### C) Measurement Uncertainty

The timely preparation of the Consolidated Financial Statements in conformity with Canadian generally accepted accounting principles requires that Management make estimates and assumptions and use judgment regarding the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the Consolidated Financial Statements and the reported amounts of revenues and expenses during the period. Such estimates primarily relate to unsettled transactions and events as of the date of the Consolidated Financial Statements. Accordingly, actual results may differ from estimated amounts as future confirming events occur.

Amounts recorded for depreciation, depletion and amortization, asset retirement costs and obligations and amounts used for ceiling test and impairment calculations are based on estimates of natural gas and crude oil reserves and future costs

required to develop those reserves. By their nature, these estimates of reserves, including the estimates of future prices and costs, and the related future cash flows are subject to measurement uncertainty, and the impact in the consolidated financial statements of future periods could be material.

The values of pension assets and obligations and the amount of pension costs charged to net earnings depend on certain actuarial and economic assumptions which by their nature are subject to measurement uncertainty.

The amount of compensation expense accrued for long-term performance based compensation arrangements are subject to Management's best estimate of whether or not the performance criteria will be met and what the ultimate payout will be.

### D) Revenue Recognition

Revenues associated with the sales of EnCana's natural gas, crude oil and natural gas liquids ("NGLs") are recognized when title passes from the Company to its customer. Natural gas and crude oil produced and sold by EnCana below or above its working interest share in the related resource properties results in production underliftings or overliftings. Underliftings are recorded as inventory and overliftings are recorded as deferred revenue. Realized gains and losses from the Company's commodity price risk management activities are recorded in revenue when the product is sold.

Marketing revenues and purchased product are recorded on a gross basis as the Company takes title to product and has risks and rewards of ownership. Revenues associated with the services provided where EnCana acts as agent are recorded as the services are provided. Revenues associated with the sale of natural gas storage services are recognized when the services are provided. Sales of electric power are recognized when power is provided to the customer.

Unrealized gains and losses from the Company's commodity price risk management activities are recorded as revenue based on the related mark-to-market calculations at the end of the respective period.

### E) Production and Mineral Taxes

Costs paid by EnCana to non-mineral interest owners based on production of natural gas, crude oil and NGLs are recognized when the product is produced.

### F) Transportation and Selling Costs

Costs paid by EnCana for the transportation and selling of natural gas, crude oil and NGLs are recognized when the product is delivered and the services provided.

### G) Employee Benefit Plans

EnCana accrues for its obligations under its employee benefit plans and the related costs, net of plan assets.

The cost of pensions and other retirement and post-employment benefits is actuarially determined using the projected benefit method based on length of service, and reflects Management's best estimate of expected plan investment performance, salary escalation, retirement ages of employees and expected future health care costs. The expected return on plan assets is based on the fair value of those assets. The obligation is discounted using a market interest rate at the beginning of the year on high quality corporate debt instruments.

Pension expense includes the cost of pension benefits earned during the current year, the interest cost on pension obligations, the expected return on pension plan assets, the amortization of the net transitional obligation, the amortization of adjustments arising from pension plan amendments and the amortization of the excess of the net actuarial gain or loss over 10 percent of the greater of the benefit obligation and the fair value of plan assets. The amortization period covers the expected average remaining service lives of employees covered by the plans.

Pension expense for the defined contribution pension plans is recorded as the benefits are earned by the employees covered by the plans.

### H) Income Taxes

EnCana follows the liability method of accounting for income taxes. Under this method, future income taxes are recorded for the effect of any difference between the accounting and income tax basis of an asset or liability, using the substantively enacted income tax rates. Accumulated future income tax balances are adjusted to reflect changes in income tax rates that are substantively enacted with the adjustment being recognized in earnings in the period that the change occurs.

### I) Earnings Per Share Amounts

Basic net earnings per common share is computed by dividing the net earnings by the weighted average number of common shares outstanding during the period. Diluted net earnings per share amounts are calculated giving effect to the potential dilution that would occur if stock options were exercised or other contracts to issue common shares were exercised or converted to common shares. The treasury stock method is used to determine the dilutive effect of stock options and other dilutive instruments. The treasury stock method assumes that proceeds received from the exercise of in-the-money stock options are used to repurchase common shares at the average market price.

### J) Cash and Cash Equivalents

Cash and cash equivalents include short-term investments, such as money market deposits or similar type instruments, with a maturity of three months or less when purchased.

### K) Inventories

Product inventories are valued at the lower of average cost and net realizable value on a first-in, first-out basis. Materials and supplies are valued at cost.

### L) Property, Plant and Equipment

#### UPSTREAM

EnCana accounts for natural gas and crude oil properties in accordance with the Canadian Institute of Chartered Accountants' guideline on full cost accounting in the oil and gas industry. Under this method, all costs directly associated with the acquisition of, exploration for and the development of, natural gas and crude oil reserves, including asset retirement costs, are capitalized on a country-by-country cost centre basis.

Costs accumulated within each cost centre are depreciated, depleted and amortized using the unit-of-production method based on estimated proved reserves determined using estimated future prices and costs. For purposes of this calculation, oil is converted to gas on an energy equivalent basis. Capitalized costs subject to depletion include estimated future costs to be incurred in developing proved reserves. Proceeds from the disposal of properties are normally deducted from the full cost pool without recognition of gain or loss unless that deduction would result in a change to the rate of depreciation, depletion and amortization of 20 percent or greater in which case a gain or loss is recorded. Costs of major development projects and costs of acquiring and evaluating significant unproved properties are excluded, on a cost centre basis, from costs subject to depletion until it is determined whether or not proved reserves are attributable to the properties, or impairment has occurred. Costs that have been impaired are included in the costs subject to depreciation, depletion and amortization.

An impairment loss is recognized in net earnings when the carrying amount of a cost centre is not recoverable and the carrying amount of the cost centre exceeds its fair value. The carrying amount of the cost centre is not recoverable if the carrying amount exceeds the sum of the undiscounted cash flows from proved reserves. If the sum of the cash flows is less than the carrying amount, the impairment loss is limited to the amount by which the carrying amount exceeds the sum of:

i. the fair value of proved and probable reserves; and

ii. the costs of unproved properties that have been subject to a separate impairment test.

#### MIDSTREAM

Midstream facilities, including natural gas storage facilities, natural gas liquids extraction plant facilities and power generation facilities, are carried at cost and depreciated on a straight-line basis over the estimated service lives of the assets, which range from 20 to 25 years. Capital assets related to pipelines are carried at cost and depreciated or amortized using the straight-line method over their economic lives, which range from 20 to 35 years.

#### CORPORATE

Costs associated with office furniture, fixtures, leasehold improvements, information technology and aircraft are carried at cost and depreciated on a straight-line basis over the estimated service lives of the assets, which range from 3 to 25 years.

### M) Capitalization of Costs

Expenditures related to renewals or betterments that improve the productive capacity or extend the life of an asset are capitalized. Maintenance and repairs are expensed as incurred.

Interest is capitalized during the construction phase of large capital projects.

### N) Amortization of Other Assets

Amortization of deferred items included in Investments and Other Assets is provided for, where applicable, on a straight-line basis over the estimated useful lives of the assets.

### O) Goodwill

Goodwill, which represents the excess of purchase price over fair value of net assets acquired, is assessed by the Company for impairment at least annually. Goodwill and all other assets and liabilities have been allocated to business levels, within the Company's segments, referred to as reporting units. To assess impairment, the fair value of each reporting unit is determined and compared to the book value of the reporting unit. If the fair value of the reporting unit is less than the book value, then a second test is performed to determine the amount of the impairment. The amount of the impairment is determined by deducting the fair value of the reporting unit's assets and liabilities from the fair value of the reporting unit to determine the implied fair value of goodwill and comparing that amount to the book value of the reporting unit's goodwill. Any excess of the book value of goodwill over the implied fair value of goodwill is the impairment amount.

### P) Asset Retirement Obligation

The fair value of estimated asset retirement obligations is recognized in the Consolidated Balance Sheet when identified and a reasonable estimate of fair value can be made. Asset retirement obligations include those legal obligations where the Company will be required to retire tangible long-lived assets such as producing well sites, offshore production platforms and natural gas processing plants. These obligations also include items for which the Company has made promissory estoppel. The asset retirement cost, equal to the initially estimated fair value of the asset retirement obligation, is capitalized as part of the cost of the related long-lived asset. Changes in the estimated obligation resulting from revisions to estimated timing or amount of undiscounted cash flows are recognized as a change in the asset retirement obligation and the related asset retirement cost.

Asset retirement costs for natural gas and crude oil assets are amortized using the unit-of-production method. Amortization of asset retirement costs are included in depreciation, depletion and amortization in the Consolidated Statement of Earnings. Increases in the asset retirement obligation resulting from the passage of time are recorded as accretion of asset retirement obligation in the Consolidated Statement of Earnings.

Actual expenditures incurred are charged against the accumulated obligation.

### Q) Stock-based Compensation

EnCana records compensation expense in the Consolidated Financial Statements for stock options granted to employees and directors using the fair value method. Fair values are determined using the Black-Scholes option-pricing model. Compensation costs are recognized over the vesting period.

Obligations for cash payments under the Company's share appreciation rights, tandem share appreciation rights, deferred share units and performance share units are accrued as compensation expense over the vesting period. Fluctuations in the price of EnCana's common shares will change the accrued compensation expense and are recognized when they occur.

### R) Derivative Financial Instruments

Derivative instruments that do not qualify as hedges, or are not designated as hedges, are recorded using the mark-to-market method of accounting whereby instruments are recorded in the Consolidated Balance Sheet as either an asset or liability with changes in fair value recognized in net earnings. Realized gains or losses from financial derivatives related to commodity prices are recognized in natural gas and crude oil revenues as the related sales occur. Unrealized gains and losses are recognized in revenues at the end of each respective reporting period. The estimated fair value of all derivative instruments is based on quoted market prices or, in their absence, third party market indications and forecasts.

Derivative financial instruments are used by EnCana to manage economic exposure to market risks relating to commodity prices, foreign currency exchange rates and interest rates. The Company's policy is not to utilize derivative financial instruments for speculative purposes.

EnCana has in place policies and procedures with respect to the required documentation and approvals for the use of derivative financial instruments and specifically ties their use, in the case of commodities, to the mitigation of market price risk associated with cash flows expected to be generated from budgeted capital programs, and in other cases to the mitigation of market price risks for specific assets and obligations. When applicable, the Company identifies relationships between financial instruments and anticipated transactions, as well as its risk management objective and the strategy for undertaking the economic hedge transaction. Where specific financial instruments are executed, the Company assesses, both at the time of purchase and on an ongoing basis, whether the financial instrument used in the particular transaction is effective in offsetting changes in fair values or cash flows of the transaction.

### S) Reclassification

Certain information provided for prior years has been reclassified to conform to the presentation adopted in 2004.

## 2 CHANGES IN ACCOUNTING POLICIES AND PRACTICES

### A) Hedging Relationships

On January 1, 2004, EnCana adopted the amendments made to the Canadian Institute of Chartered Accountants' Accounting Guideline 13 ("AcG-13") "Hedging Relationships", and Emerging Issues Committee Abstract 128 ("EIC 128") "Accounting for Trading, Speculative or Non Trading Derivative Financial Instruments". Derivative instruments that do not qualify as a hedge under AcG-13, or are not designated as a hedge, are recorded in the Consolidated Balance Sheet as either an asset or liability with changes in fair value recognized in net earnings. The Company elected not to designate any of its risk management activities in place at December 31, 2003 as accounting hedges under AcG-13 and, accordingly, accounted for all these non-hedging derivatives using the mark-to-market accounting method.

The impact on EnCana's Consolidated Financial Statements at January 1, 2004, resulted in the recognition of risk management assets with a fair value of $145 million, risk management liabilities with a fair value of $380 million and a net deferred loss of $235 million. At December 31, 2004, a net unrealized gain remains to be recognized over the next four years as follows:

| | | Unrealized Gain |
|---|---|---|
| 2005 | | |
| 3 months ended March 31 | $ – | |
| 3 months ended June 30 | 14 | |
| 3 months ended September 30 | 9 | |
| 3 months ended December 31 | 9 | |
| Total to be recognized in 2005 | | $ 32 |
| 2006 | $ 24 | |
| 2007 | 15 | |
| 2008 | 1 | |
| Total to be recognized in 2006 through to 2008 | | $ 40 |
| Total to be recognized | | $ 72 |
| Total to be recognized – Continuing Operations | | $ 73 |
| Total to be recognized – Discontinued Operations | | (1) |
| | | $ 72 |

At December 31, 2004, the remaining net deferred amounts recognized on transition are recorded in the Consolidated Balance Sheet as follows:

| As at December 31 | 2004 |
|---|---|
| Accounts receivable and accrued revenues | $ 11 |
| Investments and other assets | 4 |
| Accounts payable and accrued liabilities | 44 |
| Other liabilities | 44 |
| Total Net Deferred Gain – Continuing Operations | $ 73 |
| Total Net Deferred Loss – Discontinued Operations | (1) |
| Total Net Deferred Gain | $ 72 |

### B) Consolidation of Variable Interest Entities

On November 1, 2004, the Company retroactively adopted the new CICA Accounting Guideline 15 ("AcG-15") "Consolidation of Variable Interest Entities". AcG-15 defines a variable interest entity ("VIE") as a legal entity in which either the total equity at risk is not sufficient to permit the entity to finance its activities without additional subordinated financial support provided by other parties or the equity owners lack a controlling financial interest. The guideline requires the enterprise which absorbs the majority of a VIE's expected gains or losses, the primary beneficiary, to consolidate the VIE.

There was no effect on EnCana's Consolidated Financial Statements prior to the adoption of the guideline on November 1, 2004. Subsequent to November 1, 2004, the Company became the primary beneficiary of a VIE. At December 31, 2004, EnCana has consolidated this VIE as described in Note 4.

## 3 BUSINESS COMBINATIONS

### Tom Brown, Inc. ("TBI")

On May 19, 2004, EnCana, through a wholly owned subsidiary, completed the tender offer for the shares of Tom Brown, Inc. ("TBI"), a Denver based independent energy company, for total cash consideration of $2.3 billion plus the assumption of $406 million of long-term debt.

As part of the acquisition, EnCana acquired certain natural gas and crude oil properties in west Texas and New Mexico and the assets of Sauer Drilling Company, a subsidiary of TBI, which were designated as assets held for sale at the date of acquisition. These assets were sold on July 30, 2004.

### Alberta Energy Company Ltd. ("AEC")

On April 5, 2002, PanCanadian Energy Corporation ("PanCanadian") and Alberta Energy Company Ltd. completed a plan of arrangement (the "Arrangement") under the Business Corporations Act (Alberta). The Arrangement included a common share exchange, pursuant to which holders of common shares of AEC received 1.472 common shares of PanCanadian for each common share of AEC that they held. PanCanadian then changed its name to EnCana Corporation.

These business combinations have been accounted for using the purchase method with the results of operations included in the Consolidated Financial Statements from the dates of acquisition.

The calculation of the purchase prices and the allocations to assets and liabilities is shown below:

| | TBI | AEC |
|---|---|---|
| **Calculation of Purchase Price:** | | |
| Common Shares issued to AEC shareholders *(millions)* | | 218.5 |
| Price of Common Shares *(C$ per common share)* | | 38.43 |
| Value of Common Shares issued | | $ 5,281 |
| Fair value of AEC share options exchanged for share options of EnCana Corporation ("Share options") | | 105 |
| Cash paid for common shares of TBI | $ 2,341 | |
| Transaction costs | 13 | 94 |
| Total purchase price | $ 2,354 | $ 5,480 |
| Plus: Fair value of liabilities assumed | | |
| Current liabilities | 224 | 1,120 |
| Long-term debt (including preferred securities) | 406 | 3,714 |
| Other non-current liabilities | 39 | 180 |
| Future income taxes | 774 | 1,665 |
| **Total Purchase Price and Liabilities Assumed** | $ 3,797 | $ 12,159 |
| **Fair Value of Assets Acquired:** | | |
| Current assets (including cash acquired) | $ 425 | $ 946 |
| Property, plant and equipment, net | 2,890 | 8,897 |
| Other non-current assets | 9 | 381 |
| Goodwill | 473 | 1,935 |
| **Total Fair Value of Assets Acquired** | $ 3,797 | $ 12,159 |
| **Goodwill Allocation:** | | |
| Upstream | $ 473 | $ 1,504 |
| Midstream & Market Optimization | – | 49 |
| | 473 | 1,553 |
| Discontinued Operations | – | 382 |
| **Total Goodwill Allocation** | $ 473 | $ 1,935 |

## SEGMENTED INFORMATION

The Company has defined its continuing operations into the following segments:

- Upstream includes the Company's exploration for, and development and production of, natural gas, crude oil and natural gas liquids and other related activities. The majority of the Company's Upstream operations are located in Canada and the United States. International new venture exploration is mainly focused on opportunities in Africa, South America, the Middle East and Greenland.
- Midstream & Market Optimization is conducted by the Midstream & Marketing division. Midstream includes natural gas storage, natural gas liquids processing and power generation. The Marketing groups' primary responsibility is the sale of the Company's proprietary production. These results are included in the Upstream segment. Correspondingly, the Marketing groups also undertake market optimization activities which comprise third party purchases and sales of product that provide operational flexibility for transportation commitments, product type, delivery points and customer diversification. These activities are reflected in the Midstream & Market Optimization segment.
- Corporate includes unrealized gains or losses recorded on derivative instruments. Once amounts are settled, the realized gains and losses are recorded in the operating segment to which the derivative relates.

Midstream & Market Optimization purchases substantially all of the Company's North American Upstream production. Transactions between business segments are based on market values and eliminated on consolidation. The tables in this note present financial information on an after eliminations basis.

Operations that have been discontinued are disclosed in Note 5.

## Results of Continuing Operations *(for the years ended December 31)*

| | Upstream | | | Midstream & Market Optimization | | |
|---|---|---|---|---|---|---|
| | 2004 | 2003 | 2002 | 2004 | 2003 | 2002 |
| **Revenues, Net of Royalties** | $ 7,256 | $ 5,797 | $ 3,326 | $ 4,749 | $ 3,887 | $ 2,594 |
| **Expenses** | | | | | | |
| Production and mineral taxes | 311 | 164 | 105 | – | – | – |
| Transportation and selling | 472 | 429 | 245 | 27 | 55 | 87 |
| Operating | 1,026 | 872 | 562 | 325 | 324 | 187 |
| Purchased product | – | – | – | 4,276 | 3,455 | 2,200 |
| Depreciation, depletion and amortization | 2,271 | 1,900 | 1,115 | 70 | 48 | 36 |
| **Segment Income** | $ 3,176 | $ 2,432 | $ 1,299 | $ 51 | $ 5 | $ 84 |

| | Corporate | | | Consolidated | | |
|---|---|---|---|---|---|---|
| | 2004 | 2003 | 2002 | 2004 | 2003 | 2002 |
| **Revenues, Net of Royalties** | $ (195) | $ 2 | $ 8 | $11,810 | $ 9,686 | $ 5,928 |
| **Expenses** | | | | | | |
| Production and mineral taxes | – | – | – | 311 | 164 | 105 |
| Transportation and selling | – | – | – | 499 | 484 | 332 |
| Operating | (1) | – | – | 1,350 | 1,196 | 749 |
| Purchased product | – | – | – | 4,276 | 3,455 | 2,200 |
| Depreciation, depletion and amortization | 61 | 41 | 35 | 2,402 | 1,989 | 1,186 |
| **Segment Income** | $ (255) | $ (39) | $ (27) | 2,972 | 2,398 | 1,356 |
| Administrative | | | | 197 | 173 | 118 |
| Interest, net | | | | 397 | 283 | 286 |
| Accretion of asset retirement obligation | | | | 22 | 17 | 13 |
| Foreign exchange gain | | | | (417) | (598) | (11) |
| Stock-based compensation | | | | 17 | 18 | – |
| Gain on dispositions | | | | (113) | (1) | (33) |
| | | | | 103 | (108) | 373 |
| **Net Earnings Before Income Tax** | | | | 2,869 | 2,506 | 983 |
| Income tax expense | | | | 658 | 364 | 317 |
| **Net Earnings From Continuing Operations** | | | | $ 2,211 | $ 2,142 | $ 666 |

## Results of Continuing Operations *(for the years ended December 31)*

| | Canada | | | United States | | |
|---|---|---|---|---|---|---|
| | 2004 | 2003 | 2002 | 2004 | 2003 | 2002 |
| **Revenues, Net of Royalties** | $ 5,083 | $ 4,474 | $ 2,796 | $ 1,941 | $ 1,143 | $ 454 |
| **Expenses** | | | | | | |
| Production and mineral taxes | 87 | 56 | 70 | 224 | 108 | 35 |
| Transportation and selling | 352 | 343 | 186 | 120 | 86 | 59 |
| Operating | 685 | 642 | 456 | 119 | 60 | 35 |
| Depreciation, depletion and amortization | 1,751 | 1,511 | 862 | 475 | 293 | 202 |
| **Segment Income** | $ 2,208 | $ 1,922 | $ 1,222 | $ 1,003 | $ 596 | $ 123 |

| | Other | | | Total Upstream | | |
|---|---|---|---|---|---|---|
| | 2004 | 2003 | 2002 | 2004 | 2003 | 2002 |
| **Revenues, Net of Royalties** | $ 232 | $ 180 | $ 76 | $ 7,256 | $ 5,797 | $ 3,326 |
| **Expenses** | | | | | | |
| Production and mineral taxes | – | – | – | 311 | 164 | 105 |
| Transportation and selling | – | – | – | 472 | 429 | 245 |
| Operating | 222 | 170 | 71 | 1,026 | 872 | 562 |
| Depreciation, depletion and amortization | 45 | 96 | 51 | 2,271 | 1,900 | 1,115 |
| **Segment Income** | $ (35) | $ (86) | $ (46) | $ 3,176 | $ 2,432 | $ 1,299 |

| | Midstream | | | Market Optimization | | | Total Midstream & Market Optimization | | |
|---|---|---|---|---|---|---|---|---|---|
| | 2004 | 2003 | 2002 | 2004 | 2003 | 2002 | 2004 | 2003 | 2002 |
| **Revenues** | $ 1,450 | $ 1,084 | $ 440 | $ 3,299 | $ 2,803 | $ 2,154 | $ 4,749 | $ 3,887 | $ 2,594 |
| **Expenses** | | | | | | | | | |
| Transportation and selling | – | – | – | 27 | 55 | 87 | 27 | 55 | 87 |
| Operating | 279 | 261 | 174 | 46 | 63 | 13 | 325 | 324 | 187 |
| Purchased product | 1,071 | 762 | 169 | 3,205 | 2,693 | 2,031 | 4,276 | 3,455 | 2,200 |
| Depreciation, depletion and amortization | 68 | 40 | 24 | 2 | 8 | 12 | 70 | 48 | 36 |
| **Segment Income** | $ 32 | $ 21 | $ 73 | $ 19 | $ (16) | $ 11 | $ 51 | $ 5 | $ 84 |

## Upstream Geographic and Product Information (Continuing Operations) *(for the years ended December 31)*

| | Produced Gas | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Canada | | | United States | | | Total | | |
| | 2004 | 2003 | 2002 | 2004 | 2003 | 2002 | 2004 | 2003 | 2002 |
| **Revenues, Net of Royalties** | $ 3,928 | $ 3,396 | $ 1,882 | $ 1,776 | $ 1,051 | $ 398 | $ 5,704 | $ 4,447 | $ 2,280 |
| **Expenses** | | | | | | | | | |
| Production and mineral taxes | 65 | 52 | 50 | 205 | 101 | 32 | 270 | 153 | 82 |
| Transportation and selling | 296 | 274 | 151 | 120 | 86 | 59 | 416 | 360 | 210 |
| Operating | 400 | 342 | 255 | 119 | 60 | 35 | 519 | 402 | 290 |
| **Operating Cash Flow** | $ 3,167 | $ 2,728 | $ 1,426 | $ 1,332 | $ 804 | $ 272 | $ 4,499 | $ 3,532 | $ 1,698 |

| | Oil and NGLs | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Canada | | | United States | | | Total | | |
| | 2004 | 2003 | 2002 | 2004 | 2003 | 2002 | 2004 | 2003 | 2002 |
| **Revenues, Net of Royalties** | $ 1,155 | $ 1,078 | $ 914 | $ 165 | $ 92 | $ 56 | $ 1,320 | $ 1,170 | $ 970 |
| **Expenses** | | | | | | | | | |
| Production and mineral taxes | 22 | 4 | 20 | 19 | 7 | 3 | 41 | 11 | 23 |
| Transportation and selling | 56 | 69 | 35 | – | – | – | 56 | 69 | 35 |
| Operating | 285 | 300 | 201 | – | – | – | 285 | 300 | 201 |
| **Operating Cash Flow** | $ 792 | $ 705 | $ 658 | $ 146 | $ 85 | $ 53 | $ 938 | $ 790 | $ 711 |

| | Other | | | Total Upstream | | |
|---|---|---|---|---|---|---|
| | 2004 | 2003 | 2002 | 2004 | 2003 | 2002 |
| **Revenues, Net of Royalties** | $ 232 | $ 180 | $ 76 | $ 7,256 | $ 5,797 | $ 3,326 |
| **Expenses** | | | | | | |
| Production and mineral taxes | – | – | – | 311 | 164 | 105 |
| Transportation and selling | – | – | – | 472 | 429 | 245 |
| Operating | 222 | 170 | 71 | 1,026 | 872 | 562 |
| **Operating Cash Flow** | $ 10 | $ 10 | $ 5 | $ 5,447 | $ 4,332 | $ 2,414 |

## Capital Expenditures (Continuing Operations)

| *For the years ended December 31* | 2004 | 2003 | 2002 |
|---|---|---|---|
| Upstream | | | |
| Canada | $ 3,079 | $ 3,198 | $ 1,388 |
| United States | 1,549 | 968 | 1,176 |
| Other Countries | 79 | 78 | 117 |
| | 4,707 | 4,244 | 2,681 |
| Midstream & Market Optimization | 64 | 276 | 47 |
| Corporate | 46 | 107 | 43 |
| Total | $ 4,817 | $ 4,627 | $ 2,771 |

On December 17, 2004, EnCana acquired certain natural gas and crude oil properties in Texas for approximately $251 million. The purchase was facilitated by an unrelated party, Brown Ranger LLC, which holds the assets in trust for the Company. Pursuant to the agreement with Brown Ranger LLC, EnCana operates the properties, receives all the revenue and pays all of the expenses associated with the properties. The assets will be transferred to EnCana at the earlier of June 15, 2005 or upon the disposition of certain natural gas and crude oil properties by EnCana. EnCana has determined that the relationship with Brown Ranger LLC represents an interest in a VIE and that EnCana is the primary beneficiary of the VIE. EnCana has consolidated Brown Ranger LLC from the date of acquisition.

In addition to the capital expenditures, during 2004, EnCana divested of mature conventional oil and gas assets and other property, plant and equipment for proceeds of $1,144 million (2003 – $301 million; 2002 – $363 million).

### Additions to Goodwill

There was one addition to goodwill during 2004 (2003 – none) as a result of the business combination with Tom Brown, Inc. (see Note 3).

### Property, Plant and Equipment and Total Assets

| | | Property, Plant and Equipment | | Total Assets | |
|---|---|---|---|---|---|
| *As at December 31* | | **2004** | 2003 | **2004** | 2003 |
| Upstream | | **$ 22,097** | $ 16,757 | **$ 26,118** | $ 19,416 |
| Midstream & Market Optimization | | **804** | 784 | **1,904** | 1,879 |
| Corporate | | **239** | 229 | **1,412** | 489 |
| Assets of Discontinued Operations | *(Note 5)* | | | **1,779** | 2,326 |
| Total | | **$ 23,140** | $ 17,770 | **$ 31,213** | $ 24,110 |

### Export Sales

Sales of natural gas, crude oil and natural gas liquids produced or purchased in Canada made outside of Canada were $1,747 million (2003 – $1,484 million; 2002 – $1,333 million).

### Major Customers

In connection with the marketing and sale of EnCana's own and purchased natural gas and crude oil, for the year ended December 31, 2004, the Company had one customer (2003 – two) which individually accounted for more than 10 percent of its consolidated revenues, net of royalties. Sales to this customer, a major international integrated energy company with a high quality investment grade credit rating, were approximately $1,709 million (2003 – $1,362 million).

## 5 DISCONTINUED OPERATIONS

### 2004

On December 1, 2004, the Company completed the sale of its 100 percent interest in EnCana (U.K.) Limited for net cash consideration of approximately $2.1 billion. EnCana's U.K. operations included crude oil and natural gas interests in the U.K. central North Sea including the Buzzard, Scott and Telford oil fields, as well as other satellite discoveries and exploration licenses. A gain on sale of approximately $1.4 billion was recorded. Accordingly, these operations have been accounted for as discontinued operations.

At December 31, 2004, EnCana has decided to divest of its Ecuador operations and such operations have been accounted for as discontinued operations. EnCana's Ecuador operations include the 100 percent working interest in the Tarapoa Block, majority operating interest in Blocks 14, 17 and Shiripuno, the non-operated economic interest in Block 15 and the 36.3 percent indirect equity investment in Oleoducto de Crudos Pesados (OCP) Ltd. ("OCP"), which is the owner of a crude oil pipeline in Ecuador that ships crude oil from the producing areas of Ecuador to an export marine terminal. The Company is a shipper on the OCP Pipeline and pays commercial rates for tariffs. The majority of the Company's crude oil produced in Ecuador is sold to a single marketing company. Payments are secured by letters of credit from a major financial institution which has a high quality investment grade credit rating.

### 2003

In 2003, in two separate transactions, the Company completed the sale of its 13.75 percent working interest and a gross overriding royalty in the Syncrude Joint Venture ("Syncrude") for net cash consideration of $999 million.

### 2002

On April 24, 2002, the Company adopted formal plans to exit from the Houston-based merchant energy operation, which were completed in 2002. These operations were included in the Midstream & Market Optimization segment. Accordingly, these operations have been accounted for as discontinued operations.

On November 19, 2002, the Company announced that it had entered into agreements to sell its discontinued pipelines' operations for approximately $1 billion including the assumption of long-term debt by the purchaser. On January 2, 2003 and January 9, 2003, these sales were completed resulting in an after-tax gain on sale of $169 million.

## Consolidated Statement of Earnings

The following tables present the impact of discontinued operations in the Consolidated Statement of Earnings:

### 2004

#### UPSTREAM – UNITED KINGDOM

| *For the years ended December 31* | 2004 | 2003 | 2002 |
|---|---|---|---|
| **Revenues, Net of Royalties** | $ 153 | $ 118 | $ 103 |
| **Expenses** | | | |
| Transportation and selling | 36 | 16 | 11 |
| Operating | 36 | 18 | 11 |
| Depreciation, depletion and amortization | 118 | 74 | 39 |
| Interest, net | (9) | – | – |
| Accretion of asset retirement obligation | 3 | 1 | – |
| Foreign exchange gain | (2) | (5) | (3) |
| (Gain) loss on disposition | (1) | 1 | – |
| (Gain) loss on discontinuance | (1,364) | – | – |
| | (1,183) | 105 | 58 |
| **Net Earnings Before Income Tax** | 1,336 | 13 | 45 |
| Income tax (recovery) expense | (2) | 20 | 21 |
| **Net Earnings (Loss) From Discontinued Operations** | $ 1,338 | $ (7) | $ 24 |

#### UPSTREAM – ECUADOR

| *For the years ended December 31* | 2004 | 2003 | 2002 |
|---|---|---|---|
| **Revenues, Net of Royalties** | $ 471 | $ 412 | $ 245 |
| **Expenses** | | | |
| Production and mineral taxes | 61 | 25 | 14 |
| Transportation and selling | 60 | 45 | 21 |
| Operating | 125 | 83 | 53 |
| Depreciation, depletion and amortization | 263 | 159 | 79 |
| Administrative | – | – | 1 |
| Interest, net | (3) | 4 | 4 |
| Accretion of asset retirement obligation | 1 | 1 | – |
| Foreign exchange loss | 5 | 2 | – |
| | 512 | 319 | 172 |
| **Net (Loss) Earnings Before Income Tax** | (41) | 93 | 73 |
| Income tax (recovery) expense | (8) | 61 | 28 |
| **Net (Loss) Earnings From Discontinued Operations** | $ (33) | $ 32 | $ 45 |

## 2003

### UPSTREAM – SYNCRUDE

| *For the years ended December 31* | 2004 | 2003 | 2002 |
|---|---|---|---|
| **Revenues, Net of Royalties** | $ (1) | $ 87 | $ 232 |
| **Expenses** | | | |
| Transportation and selling | – | 2 | 3 |
| Operating | – | 46 | 105 |
| Depreciation, depletion and amortization | – | 7 | 16 |
| Interest, net | – | – | 1 |
| Loss on discontinuance | 2 | – | – |
| | 2 | 55 | 125 |
| **Net (Loss) Earnings Before Income Tax** | (3) | 32 | 107 |
| Income tax expense | – | 8 | 28 |
| **Net (Loss) Earnings From Discontinued Operations** | $ (3) | $ 24 | $ 79 |

## 2002

### MIDSTREAM & MARKET OPTIMIZATION

| | Merchant Energy | | Midstream – Pipelines | | Total | |
|---|---|---|---|---|---|---|
| *For the years ended December 31* | 2003 | 2002 | 2003 | 2002 | 2003 | 2002 |
| **Revenues** | $ – | $ 922 | $ – | $ 135 | $ – | $ 1,057 |
| **Expenses** | | | | | | |
| Operating | – | – | – | 50 | – | 50 |
| Purchased product | – | 931 | – | – | – | 931 |
| Depreciation, depletion and amortization | – | – | – | 18 | – | 18 |
| Administrative | – | 22 | – | – | – | 22 |
| Interest, net | – | – | – | 19 | – | 19 |
| Foreign exchange gain | – | – | – | (3) | – | (3) |
| Loss (gain) on discontinuance | – | 19 | (220) | – | (220) | 19 |
| | – | 972 | (220) | 84 | (220) | 1,056 |
| **Net (Loss) Earnings Before Income Tax** | – | (50) | 220 | 51 | 220 | 1 |
| Income tax (recovery) expense | – | (17) | 51 | 20 | 51 | 3 |
| **Net (Loss) Earnings From Discontinued Operations** | $ – | $ (33) | $ 169 | $ 31 | $ 169 | $ (2) |

### CONSOLIDATED TOTAL

| *For the years ended December 31* | 2004 | 2003 | 2002 |
|---|---|---|---|
| **Revenues, Net of Royalties** | $ 623 | $ 617 | $ 1,637 |
| **Expenses** | | | |
| Production and mineral taxes | 61 | 25 | 14 |
| Transportation and selling | 96 | 63 | 35 |
| Operating | 161 | 147 | 219 |
| Purchased product | – | – | 931 |
| Depreciation, depletion and amortization | 381 | 240 | 152 |
| Administrative | – | – | 23 |
| Interest, net | (12) | 4 | 24 |
| Accretion of asset retirement obligation | 4 | 2 | – |
| Foreign exchange loss (gain) | 3 | (3) | (6) |
| (Gain) loss on disposition | (1) | 1 | – |
| (Gain) loss on discontinuance | (1,362) | (220) | 19 |
| | (669) | 259 | 1,411 |
| **Net Earnings Before Income Tax** | 1,292 | 358 | 226 |
| Income tax (recovery) expense | (10) | 140 | 80 |
| **Net Earnings From Discontinued Operations** | $ 1,302 | $ 218 | $ 146 |

## Consolidated Balance Sheet

The impact of the discontinued operations in the Consolidated Balance Sheet is as follows:

| *As at December 31* | 2004 | 2003 |
|---|---|---|
| **Assets** | | |
| Cash and cash equivalents | $ 14 | $ 35 |
| Accounts receivable and accrued revenues | 124 | 202 |
| Risk management | 3 | – |
| Inventories | 15 | 16 |
| | 156 | 253 |
| Property, plant and equipment, net | 1,295 | 1,775 |
| Investments and other assets | 328 | 298 |
| | $ 1,779 | $ 2,326 |
| **Liabilities** | | |
| Accounts payable and accrued liabilities | $ 96 | $ 231 |
| Income tax payable | 101 | 33 |
| Risk management | 72 | – |
| | 269 | 264 |
| Asset retirement obligation | 22 | 47 |
| Future income taxes | 91 | 206 |
| | 382 | 517 |
| **Net Assets of Discontinued Operations** | $ 1,397 | $ 1,809 |

The prices used in the ceiling test evaluation of the Company's crude oil reserves in Ecuador at December 31, 2004 were as follows:

| | 2005 | 2006 | 2007 | 2008 | 2009 | % increase to 2016 |
|---|---|---|---|---|---|---|
| Crude Oil *($/barrel)* | $ 33.27 | $ 29.89 | $ 23.47 | $ 23.43 | $ 23.45 | 13% |

### ACQUISITION/DISPOSITION

On January 31, 2003, the Company acquired the Ecuador interests of Vintage Petroleum Inc. ("Vintage") for net cash consideration of $116 million. During the fourth quarter of 2003, the Company disposed of its interest in Block 27 in Ecuador for approximately $14 million.

### COMMITMENTS AND CONTINGENCIES

The Company is a shipper on the OCP Pipeline and has tariff commitments as follows:

| *As at December 31, 2004* | 2005 | 2006 | 2007 | 2008 | 2009 | Thereafter | Total |
|---|---|---|---|---|---|---|---|
| Pipeline Transportation | $ 99 | $ 93 | $ 92 | $ 93 | $ 95 | $ 837 | $ 1,309 |

In Ecuador, a subsidiary of EnCana has a 40 percent non-operated economic interest in relation to Block 15 pursuant to a contract with a subsidiary of Occidental Petroleum Corporation. During the year, Occidental Petroleum Corporation filed a Form 8-K indicating that its subsidiary had received formal notification from Petroecuador, the state oil company of Ecuador, initiating proceedings to determine if the subsidiary had violated the Hydrocarbons Law and its Participation Contract for Block 15 with Petroecuador and whether such violations constitute grounds for terminating the Participation Contract.

In its Form 8-K, Occidental Petroleum Corporation indicated that it believes that it has complied with all material obligations under the Participation Contract and that any termination of the Participation Contract by Ecuador based upon these stated allegations would be unfounded and would constitute an unlawful expropriation under international treaties.

In addition to the above, the Company is proceeding with its arbitration related to value-added tax ("VAT") owed to EnCana ($139 million at December 31, 2004). EnCana is also in discussions related to certain income tax matters related to the deductibility of interest expense in Ecuador.

## 6 DISPOSITIONS (ACQUISITIONS)

| *For the years ended December 31* | 2004 | 2003 | 2002 |
|---|---|---|---|
| **Acquisitions** | | | |
| Petrovera Resources | $ (253) | $ – | $ – |
| Savannah | – | (91) | – |
| Other | (34) | – | – |
| | (287) | (91) | – |
| **Dispositions** | | | |
| Petrovera Resources | 540 | – | – |
| Alberta Ethane Gathering System Joint Venture | 108 | – | – |
| Kingston CoGen Limited Partnership | 25 | – | – |
| EnCana Suffield Gas Pipeline Inc. | – | – | 60 |
| | 673 | – | 60 |
| | $ 386 | $ (91) | $ 60 |

On December 22, 2004 EnCana completed the disposition of its interest in the Alberta Ethane Gathering System Joint Venture for approximately $108 million, including working capital. A $54 million pre-tax gain was recorded on this sale.

On December 15, 2004, EnCana sold its 25 percent limited partnership interest in Kingston CoGen Limited Partnership ("Kingston") for net cash consideration of $25 million. A pre-tax gain of $28 million was recorded on this sale.

In March 2004, the Company sold its equity investment in a well servicing company for approximately $44 million, recording a pre-tax gain on sale of $34 million.

On February 18, 2004, the Company sold its 53.3 percent interest in Petrovera Resources for approximately $287 million, including working capital adjustments. In order to facilitate the transaction, the Company purchased the 46.7 percent interest of its partner for approximately $253 million, including working capital adjustments, and then sold the 100 percent interest for a total of approximately $540 million, including working capital adjustments. In accordance with full cost accounting for oil and gas activities, proceeds were credited to property, plant and equipment.

On July 18, 2003, the Company acquired the common shares of Savannah Energy Inc. ("Savannah") for net cash consideration of $91 million. Savannah's operations are in Texas, U.S.A.

In 2002, the Company sold its interest in EnCana Suffield Gas Pipeline Inc. for $60 million, recording a pre-tax gain on sale of $33 million.

## 7 INTEREST, NET

| *For the years ended December 31* | 2004 | 2003 | 2002 |
|---|---|---|---|
| Interest Expense – Long-Term Debt | $ 385 | $ 281 | $ 252 |
| Early Retirement of Long-Term Debt | (16) | – | 34 |
| Interest Expense – Other | 42 | 20 | 10 |
| Interest Income | (14) | (18) | (10) |
| | $ 397 | $ 283 | $ 286 |

EnCana has entered into a series of one or more interest rate swaps, foreign exchange swaps and option transactions on certain of its long-term notes and debentures detailed below (see also Note 13). The net effect of these transactions reduced interest costs in 2004 by $22 million (2003 – $23 million; 2002 – $20 million).

| | Principal Amount | Indenture Interest | Net Swap to | Effective Rate |
|---|---|---|---|---|
| 8.75% due November 9, 2005 | US$73 million | C$ Fixed | US$ Fixed* | 4.99% |
| C$200 million | | | | |
| | US$73 million | C$ Fixed | US$ Floating* | 3 month LIBOR less 4 basis points |
| 7.50% due August 25, 2006 | | | | |
| C$100 million | US$73 million | C$ Fixed | US$ Fixed* | 4.14% |
| 5.80% due June 2, 2008 | US$71 million | C$ Fixed | US$ Fixed* | 4.80% |
| C$225 million | | | | |
| | C$125 million | C$ Fixed | C$ Floating | 3 month Bankers' Acceptance less 5 basis points |

** These instruments have been subject to multiple swap transactions.*

## 8 FOREIGN EXCHANGE GAIN

| *For the years ended December 31* | 2004 | 2003 | 2002 |
|---|---|---|---|
| Unrealized Foreign Exchange Gain on Translation of U.S. Dollar Debt Issued in Canada | $ (285) | $ (545) | $ (23) |
| Realized Foreign Exchange (Gains) Losses | (132) | (53) | 12 |
| | $ (417) | $ (598) | $ (11) |

## 9 INCOME TAXES

The provision for income taxes is as follows:

| *For the years ended December 31* | 2004 | 2003 | 2002 |
|---|---|---|---|
| Current | | | |
| Canada | $ 594 | $ (136) | $ (26) |
| United States | (12) | 39 | (31) |
| Other | (15) | (16) | (9) |
| Total Current Tax | 567 | (113) | (66) |
| Future | 200 | 836 | 403 |
| Future Tax Rate Reductions | (109) | (359) | (20) |
| Total Future Tax | 91 | 477 | 383 |
| | $ 658 | $ 364 | $ 317 |

The following table reconciles income taxes calculated at the Canadian statutory rate with actual income taxes:

| *For the years ended December 31* | 2004 | 2003 | 2002 |
|---|---|---|---|
| Net Earnings Before Income Tax | $ 2,869 | $ 2,506 | $ 983 |
| Canadian Statutory Rate | 39.1% | 41.0% | 42.3% |
| Expected Income Tax | 1,123 | 1,026 | 416 |
| Effect on Taxes Resulting from: | | | |
| Non-deductible Canadian crown payments | 192 | 231 | 147 |
| Canadian resource allowance | (246) | (258) | (200) |
| Canadian resource allowance on unrealized risk management losses | (10) | – | – |
| Statutory and other rate differences | (55) | (45) | (35) |
| Effect of tax rate changes | (109) | (359) | (20) |
| Non-taxable capital gains | (91) | (119) | – |
| Previously unrecognized capital losses | 17 | (119) | – |
| Tax basis retained on dispositions | (179) | – | – |
| Large corporations tax | 24 | 27 | 23 |
| Other | (8) | (20) | (14) |
| | $ 658 | $ 364 | $ 317 |
| Effective Tax Rate | 22.9% | 14.5% | 32.2% |

The net future income tax liability is comprised of:

| *As at December 31* | 2004 | 2003 |
|---|---|---|
| Future Tax Liabilities | | |
| Property, plant and equipment in excess of tax values | $ 4,472 | $ 3,199 |
| Timing of Partnership items | 1,005 | 1,162 |
| Future Tax Assets | | |
| Net operating losses carried forward | (103) | (99) |
| Other | (181) | (106) |
| Net Future Income Tax Liability | $ 5,193 | $ 4,156 |

The approximate amounts of tax pools available are as follows:

| *As at December 31* | 2004 | 2003 |
|---|---|---|
| Canada | $ 7,183 | $ 6,904 |
| United States | 3,009 | 2,112 |
| | $ 10,192 | $ 9,016 |

Included in the above tax pools are $275 million (2003 – $256 million) related to non-capital or net operating losses available for carry forward to reduce taxable income in future years.

The current income tax provision includes amounts payable or recoverable in respect of Canadian partnership earnings included in the Consolidated Financial Statements for partnerships that have a year-end that is after that of EnCana.

## 10 INVENTORIES

| *As at December 31* | 2004 | 2003 |
|---|---|---|
| Product | | |
| Upstream | $ 14 | $ 6 |
| Midstream & Market Optimization | 497 | 546 |
| Parts and Supplies | 2 | 5 |
| | $ 513 | $ 557 |

## 11 PROPERTY, PLANT AND EQUIPMENT, NET

| *As at December 31* | 2004 | | | 2003 | | |
|---|---|---|---|---|---|---|
| | Cost | Accumulated DD&A* | Net | Cost | Accumulated DD&A* | Net |
| Upstream | | | | | | |
| Canada | $ 24,390 | $ (9,775) | $ 14,615 | $ 20,607 | $ (7,500) | $ 13,107 |
| United States | 8,360 | (1,056) | 7,304 | 4,062 | (523) | 3,539 |
| Other Countries | 425 | (247) | 178 | 316 | (205) | 111 |
| Total Upstream | 33,175 | (11,078) | 22,097 | 24,985 | (8,228) | 16,757 |
| Midstream & Market Optimization | 975 | (171) | 804 | 915 | (131) | 784 |
| Corporate | 455 | (216) | 239 | 320 | (91) | 229 |
| | $ 34,605 | $(11,465) | $ 23,140 | $ 26,220 | $ (8,450) | $ 17,770 |

** Depreciation, depletion and amortization*

Included in Midstream is $102 million (2003 – $97 million; 2002 – $47 million) related to cushion gas, required to operate the gas storage facilities, which is not subject to depletion.

Included in property, plant and equipment are asset retirement costs, net of amortization, of $393 million (2003 – $212 million). Administrative costs have not been capitalized as part of the capital expenditures.

Upstream costs in respect of significant unproved properties and major development projects excluded from depletable costs at the end of the year were:

| As at December 31 | 2004 | 2003 | 2002 |
|---|---|---|---|
| Canada | $ 1,444 | $ 1,444 | $ 1,035 |
| United States | 1,119 | 499 | 604 |
| Other Countries | 177 | 112 | 111 |
| | $ 2,740 | $ 2,055 | $ 1,750 |

The costs excluded from depletable costs in Other Countries represents costs related to unproved properties incurred in cost centres that are considered to be in the pre-production stage. Currently, there are no proved reserves in these cost centres. All costs, net of any associated revenues, in these cost centres have been capitalized. Ultimate recoverability of these costs will be dependent upon the finding of proved oil and natural gas reserves. At December, 31, 2004, the Company completed its impairment review of pre-production cost centres and determined that $23 million of costs should be charged to the Consolidated Statement of Earnings (2003 – $85 million; 2002 – nil).

The prices used in the ceiling test evaluation of the Company's crude oil and natural gas reserves at December 31, 2004 were:

| | 2005 | 2006 | 2007 | 2008 | 2009 | % increase to 2016 |
|---|---|---|---|---|---|---|
| Natural Gas *($/Mcf)* | | | | | | |
| Canada | $ 6.00 | $ 5.34 | $ 4.52 | $ 4.45 | $ 4.58 | 12% |
| United States | 6.24 | 5.61 | 4.35 | 4.77 | 4.77 | 13% |
| Crude Oil *($/barrel)* | | | | | | |
| Canada | $ 28.66 | $ 24.38 | $ 17.03 | $ 17.20 | $ 16.88 | 7% |
| United States | 43.51 | 38.84 | 26.95 | 26.49 | 26.45 | 18% |
| Natural Gas Liquids *($/barrel)* | | | | | | |
| Canada | $ 38.61 | $ 33.99 | $ 25.65 | $ 25.41 | $ 25.25 | 17% |
| United States | 38.18 | 34.54 | 26.93 | 27.14 | 27.22 | 14% |

## 12 INVESTMENTS AND OTHER ASSETS

| As at December 31 | 2004 | 2003 |
|---|---|---|
| Equity Investments | $ 8 | $ 57 |
| Marketing Contracts | 12 | 22 |
| Deferred Financing Costs | 61 | 35 |
| Deferred Pension Plan and Savings Plan | 64 | 53 |
| Prepaid Capital and Other | 189 | 101 |
| | $ 334 | $ 268 |

### Equity Investments

Included in Equity Investments is a 36 percent indirect equity investment in Oleoducto Trasandino which owns a crude oil pipeline that ships crude oil from the producing areas of Argentina to refineries in Chile. In the second quarter of 2004, a $35 million impairment charge was made to depreciation, depletion and amortization on the Company's interest in Oleoducto Trasandino.

## 13 LONG-TERM DEBT

| As at December 31 | Note | 2004 | 2003 |
|---|---|---|---|
| **Canadian Dollar Denominated Debt** | | | |
| Revolving credit and term loan borrowings | B | $ 1,515 | $ 1,425 |
| Unsecured notes and debentures | C | 1,309 | 1,335 |
| Preferred securities | D | – | 252 |
| | | 2,824 | 3,012 |
| **U.S. Dollar Denominated Debt** | | | |
| Revolving credit and term loan borrowings | E | 399 | 417 |
| Unsecured notes and debentures | F | 4,641 | 2,713 |
| Preferred securities | D | – | 150 |
| | | 5,040 | 3,280 |
| Increase in Value of Debt Acquired | G | 66 | 83 |
| Current Portion of Long-Term Debt | H | (188) | (287) |
| | | $ 7,742 | $ 6,088 |

### A) Overview

#### REVOLVING CREDIT AND TERM LOAN BORROWINGS

At December 31, 2004, EnCana had in place a revolving credit facility for $4.5 billion Canadian dollars or its equivalent amount in U.S. dollars ($3.7 billion). The facility consists of two tranches of C$1.7 billion ($1.4 billion) and C$2.8 billion ($2.3 billion) respectively. The first tranche is fully revolving for a period of three years from the date of the agreement, October 2004. This tranche is extendible annually for an additional one year period at the option of the lenders and upon notice from EnCana. The second tranche is fully revolving for a period of five years from the date of the agreement, October 2004. This tranche is extendible annually for an additional one year period at the option of the lenders and upon notice from the Company. The facility is unsecured and bears interest at either the lenders' rates for Canadian prime commercial loans, U.S. base rate loans, Bankers' Acceptances rates, or at LIBOR plus applicable margins.

To fund the acquisition of Tom Brown, Inc., EnCana arranged a $3 billion non-revolving term loan facility. Initially, $1.8 billion was drawn on this facility. At December 31, 2004, this facility has been completely repaid and cancelled.

At December 31, 2004, one of EnCana's subsidiaries had in place a credit facility totaling $600 million (C$722 million). The facility is guaranteed by EnCana Corporation and fully revolving for five years from the date of the Agreement, December 2004. The facility is extendible annually for an additional one year period at the option of the lenders and upon notice from the subsidiary. This facility bears interest at either the lenders' U.S. base rate or at LIBOR plus applicable margins.

Revolving credit and term loan borrowings include Bankers' Acceptances and Commercial Paper of $1,559 million (2003 – $1,749 million) maturing at various dates with a weighted average interest rate of 2.83% (2003 – 2.55%) and LIBOR loans of $355 million (2003 – $65 million) with a weighted average interest rate of 2.98% (2003 – 1.69%). These amounts are fully supported and Management expects that they will continue to be supported by revolving credit and term loan facilities that have no repayment requirements within the next year.

Standby fees paid in 2004 relating to revolving credit and term loan agreements were approximately $5 million (2003 – $3 million; 2002 – $3 million).

#### UNSECURED NOTES AND DEBENTURES

Unsecured notes and debentures include medium term notes and senior notes that are issued from time to time under trust indentures. The Company's current medium term note program was renewed in 2003 with C$1 billion ($831 million) unutilized at December 31, 2004. The notes may be denominated in Canadian dollars or in foreign currencies.

EnCana has in place a shelf prospectus for U.S. Unsecured Notes in the amount of $2 billion under the Multijurisdictional Disclosure System. The shelf prospectus provides that debt securities in U.S. dollars or other foreign currencies may be issued from time to time in one or more series. Terms of the notes, including interest at either fixed or floating rates and expiry dates, are determined by reference to market conditions at the date of issue. At December 31, 2004, $2 billion of the shelf prospectus remains unutilized.

EnCana has an indirect wholly owned subsidiary, EnCana Holdings Finance Corp., which has in place a shelf prospectus in the amount of $2 billion under the Multijurisdictional Disclosure System. The shelf prospectus provides that debt securities in U.S. dollars or other foreign currencies may be issued from time to time in one or more series. Terms of the notes, including interest at either fixed or floating rates and expiry dates, are determined by reference to market conditions at the date of issue. The debt securities issued under this shelf prospectus are fully and unconditionally guaranteed by EnCana Corporation. EnCana has also obtained certain exemption orders from Canadian securities regulatory authorities that allow the filing of certain financial and other information of EnCana to satisfy certain continuous disclosure obligations of EnCana Holdings Finance Corp. At December 31, 2004, $1 billion of the shelf prospectus remains unutilized.

### B) Canadian revolving credit and term loan borrowings

| | C$ Principal Amount | 2004 | 2003 |
|---|---|---|---|
| Bankers' Acceptances | $ 615 | $ 511 | $ 598 |
| Commercial Paper | 1,209 | 1,004 | 799 |
| Cogeneration Facility, matures March 31, 2016* | – | – | 28 |
| | $ 1,824 | $ 1,515 | $ 1,425 |

* On December 15, 2004, EnCana sold its limited partnership interest in Kingston. See Note 6.

### C) Canadian unsecured notes and debentures

| | C$ Principal Amount | 2004 | 2003 |
|---|---|---|---|
| 6.60% due June 30, 2004 | $ – | $ – | $ 39 |
| 7.00% due December 1, 2004 | – | – | 77 |
| 5.95% due October 1, 2007 | 200 | 166 | 155 |
| 5.30% due December 3, 2007 | 300 | 248 | 232 |
| 5.95% due June 2, 2008 | 100 | 83 | 77 |
| 5.80% due June 2, 2008 | 125 | 104 | 97 |
| 5.80% due June 19, 2008 | 100 | 83 | 77 |
| 6.10% due June 1, 2009 | 150 | 125 | 116 |
| 7.15% due December 17, 2009 | 150 | 125 | 116 |
| 8.50% due March 15, 2011 | 50 | 42 | 39 |
| 7.10% due October 11, 2011 | 200 | 166 | 155 |
| 7.30% due September 2, 2014 | 150 | 125 | 116 |
| 5.50%/6.20% due June 23, 2028 | 50 | 42 | 39 |
| | $ 1,575 | $ 1,309 | $ 1,335 |

### D) Preferred securities

| | C$ Principal Amount | 2004 | 2003 |
|---|---|---|---|
| Canadian Dollar | | | |
| 7.00% due March 23, 2034 | $ – | $ – | $ 97 |
| 8.50% due September 30, 2048 | – | – | 155 |
| | $ – | – | 252 |
| U.S. Dollar | | | |
| 9.50% due September 30, 2048 | | – | 150 |
| | | $ – | $ 402 |

All of the preferred securities were redeemed during 2004 at par plus accrued and unpaid interest.

### E) U.S. revolving credit and term loan borrowings

| | 2004 | 2003 |
|---|---|---|
| Commercial Paper | $ 44 | $ 352 |
| LIBOR Loan | 355 | 65 |
| | $ 399 | $ 417 |

### F) U.S. unsecured notes and debentures

| | C$ Amount | 2004 | 2003 |
|---|---|---|---|
| Floating Rate | | | |
| 8.40% due December 15, 2004 | $ – | $ – | $ 73 |
| 8.75% due November 9, 2005 | 88* | 73 | 73 |
| Fixed Rate | | | |
| 8.75% due November 9, 2005 | 88* | 73 | 73 |
| 7.50% due August 25, 2006 | 88* | 73 | 73 |
| 5.80% due June 2, 2008 | 85* | 71 | 71 |
| 4.60% due August 15, 2009 | | 250 | – |
| 7.65% due September 15, 2010 | | 200 | 200 |
| 6.30% due November 1, 2011 | | 500 | 500 |
| 7.25% due September 15, 2013 | | 1 | – |
| 4.75% due October 15, 2013 | | 500 | 500 |
| 5.80% due May 1, 2014 | | 1,000 | – |
| 8.125% due September 15, 2030 | | 300 | 300 |
| 7.20% due November 1, 2031 | | 350 | 350 |
| 7.375% due November 1, 2031 | | 500 | 500 |
| 6.50% due August 15, 2034 | | 750 | – |
| | | $ 4,641 | $ 2,713 |

* *The Company has entered into a series of cross-currency and interest rate swap transactions that effectively convert these Canadian dollar denominated notes to U.S. dollars. The effective U.S. dollar principal is shown in the table.*

The 5.80% Notes due May 1, 2014 were issued by the Company's indirect wholly owned subsidiary, EnCana Holdings Finance Corp. These notes are fully and unconditionally guaranteed by EnCana Corporation.

### G) Increase in value of debt acquired

Certain of the notes and debentures of the Company were acquired in business combinations and were accounted for at their fair value at the date of acquisition. The difference between the fair value and the principal amount of the debt is being amortized over the remaining life of the outstanding debt acquired, approximately 22 years.

### H) Current portion of long-term debt

| | 2004 | 2003 |
|---|---|---|
| 7.00% Coupon Reset Subordinated Term Securities due March 23, 2034 | $ – | $ 97 |
| 6.60% Medium Term Note due June 30, 2004 | – | 39 |
| 7.00% Medium Term Note due December 1, 2004 | – | 77 |
| 8.40% Medium Term Note due December 15, 2004 | – | 73 |
| 5.50%/6.20% Medium Term Note due June 23, 2028 | 42 | – |
| 8.75% Unsecured Note due November 9, 2005 | 146 | – |
| Cogeneration Facility | – | 1 |
| | $ 188 | $ 287 |

The 5.50%/6.20% Medium Term Note due June 23, 2028 has a put option attached to it whereby holders of the note may require EnCana to repay the outstanding note on June 23, 2005, if the notice is given prior to June 9, 2005 that the option will be exercised. Should notice not be received, the note is then payable on June 23, 2028.

### l) Mandatory debt payments

| | C$ Principal Amount | US$ Principal Amount | Total US$ Equivalent |
|---|---|---|---|
| 2005 | $ 50 | $ 146 | $ 188 |
| 2006 | – | 73 | 73 |
| 2007 | 500 | – | 414 |
| 2008 | 325 | 71 | 341 |
| 2009 | 300 | 250 | 500 |
| Thereafter | 2,224 | 4,500 | 6,348 |
| Total | $ 3,399 | $ 5,040 | $ 7,864 |

The amount due in 2005 excludes Bankers' Acceptances and Commercial Paper, which are fully supported by revolving credit and term loan facilities that have no repayment requirements within the next year.

## 14 ASSET RETIREMENT OBLIGATION

The following table presents the reconciliation of the beginning and ending aggregate carrying amount of the obligation associated with the retirement of oil and gas properties.

| *As at December 31* | 2004 | 2003 |
|---|---|---|
| Asset Retirement Obligation, Beginning of Year | $ 383 | $ 288 |
| Liabilities Incurred | 98 | 45 |
| Liabilities Settled | (16) | (23) |
| Liabilities Disposed | (35) | – |
| Change in Estimated Future Cash Flows | 124 | – |
| Accretion Expense | 22 | 17 |
| Other | 35 | 56 |
| Asset Retirement Obligation, End of Year | $ 611 | $ 383 |

The total undiscounted amount of estimated cash flows required to settle the obligation is $3,695 million (2003 – $3,118 million), which has been discounted using a credit-adjusted risk-free rate of 6.0 percent (2003 – 5.9 percent). Most of these obligations are not expected to be paid for several years, or decades, in the future and will be funded from general company resources at that time.

## 15 SHARE CAPITAL

### Authorized

The Company is authorized to issue an unlimited number of Common Shares, an unlimited number of First Preferred Shares and an unlimited number of Second Preferred Shares.

### Issued and Outstanding

| *As at December 31* | 2004 | | 2003 | |
|---|---|---|---|---|
| | Number *(millions)* | Amount | Number *(millions)* | Amount |
| Common Shares Outstanding, Beginning of Year | 460.6 | $ 5,305 | 478.9 | $ 5,511 |
| Shares Issued under Option Plans | 9.7 | 281 | 5.5 | 114 |
| Shares Repurchased | (20.0) | (287) | (23.8) | (320) |
| Common Shares Outstanding, End of Year | 450.3 | $ 5,299 | 460.6 | $ 5,305 |

### Normal Course Issuer Bid

On October 26, 2004, the Company received regulatory approval for a new Normal Course Issuer Bid commencing October 29, 2004. Under this bid, the Company may purchase for cancellation up to 23,114,500 of its Common Shares, representing five percent of the approximately 462.29 million Common Shares outstanding as of the filing of the bid on October 22, 2004. On February 4, 2005, the Company received regulatory approval for an amendment to the Normal Course Issuer Bid which increases the number of shares available for purchase from five percent of the issued and outstanding Common Shares to ten percent of the public float of Common Shares (a total of approximately 46.1 million Common Shares). The current Normal Course Issuer Bid expires on October 28, 2005.

On October 20, 2003, the Company received regulatory approval for a new Normal Course Issuer Bid commencing October 22, 2003. Under this bid, the Company could purchase for cancellation up to 23,212,341 of its Common Shares, representing five percent of the 464,246,813 Common Shares outstanding as of October 14, 2003.

In 2004, the Company purchased, for cancellation, 19,983,600 Common Shares for total consideration of $1,004 million. Of the $1,004 million paid, $287 million was charged to Share capital, $46 million was charged to Paid in surplus and $671 million was charged to Retained earnings.

### Stock Options

EnCana has stock-based compensation plans that allow employees to purchase Common Shares of the Company. Option exercise prices approximate the market price for the Common Shares on the date the options were issued. Options granted under the plans are generally fully exercisable after three years and expire five years after the grant date. Options granted under predecessor and/or related company replacement plans expire up to 10 years from the date the options were granted.

In conjunction with the business combination transaction with AEC described in Note 3, options to purchase AEC common shares were replaced with options to purchase Common Shares of EnCana ("AEC replacement plan") in a manner consistent with the provisions of the AEC stock option plan. Options granted under the AEC plan prior to April 21, 1999 expire after seven years and options granted after April 20, 1999 expire after five years. The business combination resulted in these replacement options, along with all options then outstanding under the EnCana plan, becoming exercisable after the close of business on April 5, 2002.

#### EnCana Plan

Pursuant to the terms of a stock option plan, options may be granted to certain key employees to purchase Common Shares of the Company. Options granted prior to February 27, 1997, are exercisable at half the number of options granted after two years and are fully exercisable after three years. The options expire 10 years after the date granted. Options granted on or after February 27, 1997, and prior to November 4, 1999, are exercisable after three years and expire five years after the date granted. Options granted on or after November 4, 1999, are exercisable at 30 percent of the number granted after one year, an additional 30 percent of the number granted after two years, are fully exercisable after three years and expire five years after the date granted. For stock options granted after February 27, 1997, and prior to November 4, 1999, the employees can surrender their options in exchange for, at the election of the Company, cash or a payment in common stock for the difference between the market price and exercise price. All options issued in 2004 have an associated Tandem Share Appreciation Right ("TSAR") attached to them (see Note 16).

#### Canadian Pacific Limited Replacement Plan

As part of the 2001 reorganization of Canadian Pacific Limited ("CPL"), EnCana's former parent company, CPL stock options were replaced with stock options granted by the Company in a manner that was consistent with the provisions of the CPL stock option plan. Under CPL's stock option plan, options were granted to certain key employees to purchase common shares of CPL at a price not less than the market value of the shares at the grant date. The options expire 10 years after the grant date and are all exercisable.

### DIRECTORS' PLAN

Effective April 5, 2002, the Company amended the director stock option plan. Under the terms of the plan, new non-employee directors were given an initial grant of 15,000 options to purchase common shares of the Company. Thereafter, there was an annual grant of 7,500 options to each non-employee director. Options, which expire five years after the grant date, are 100 percent exercisable on the earlier of the next annual general meeting following the grant date and the first anniversary of the grant date. On October 23, 2003, issuances of stock options under this plan were discontinued.

The following tables summarize the information about options to purchase Common Shares that have no TSAR attached to them:

| *As at December 31* | **2004** | | 2003 | | 2002 | |
|---|---|---|---|---|---|---|
| | **Stock Options** *(millions)* | **Weighted Average Exercise Price (C$)** | Stock Options *(millions)* | Weighted Average Exercise Price (C$) | Stock Options *(millions)* | Weighted Average Exercise Price (C$) |
| Outstanding, Beginning of Year | **28.8** | **43.13** | 29.6 | 39.74 | 10.5 | 32.31 |
| Granted under EnCana Plan | **–** | **–** | 6.3 | 47.98 | 12.1 | 48.13 |
| Granted under AEC Replacement Plan | **–** | **–** | – | – | 13.1 | 32.01 |
| Granted under Directors' Plan | **–** | **–** | 0.1 | 47.87 | 0.1 | 48.04 |
| Exercised | **(9.7)** | **36.63** | (5.5) | 29.11 | (5.5) | 25.20 |
| Forfeited | **(1.0)** | **47.50** | (1.7) | 41.18 | (0.7) | 43.81 |
| Outstanding, End of Year | **18.1** | **46.29** | 28.8 | 43.13 | 29.6 | 39.74 |
| Exercisable, End of Year | **10.8** | **45.09** | 15.6 | 38.92 | 17.7 | 34.10 |

| *As at December 31, 2004* | Outstanding Options | | | Exercisable Options | |
|---|---|---|---|---|---|
| Range of Exercise Price *(C$)* | Number of Options Outstanding *(millions)* | Weighted Average Remaining Contractual Life *(years)* | Weighted Average Exercise Price (C$) | Number of Options Outstanding *(millions)* | Weighted Average Exercise Price (C$) |
| 13.50 to 19.99 | 0.1 | 0.2 | 18.49 | 0.1 | 18.49 |
| 20.00 to 24.99 | 0.6 | 3.5 | 22.69 | 0.6 | 22.69 |
| 25.00 to 29.99 | 0.4 | 1.3 | 26.18 | 0.4 | 26.18 |
| 30.00 to 43.99 | 0.5 | 1.7 | 40.18 | 0.4 | 39.93 |
| 44.00 to 53.00 | 16.5 | 2.4 | 47.97 | 9.3 | 47.87 |
| | 18.1 | 2.4 | 46.29 | 10.8 | 45.09 |

At December 31, 2004, there were 8.0 million common shares reserved for issuance under stock option plans (2003 – 7.8 million; 2002 – 12.4 million).

EnCana has recorded stock-based compensation expense in the Consolidated Statement of Earnings for stock options granted to employees and directors in 2003 using the fair value method. Compensation expense has not been recorded in the Consolidated Statement of Earnings related to stock options granted prior to 2003. If the Company had applied the fair value method to options granted prior to 2003, pro forma Net Earnings and Net Earnings per Common Share in 2004 would have been $3,476 million; $7.55 per common share – basic; $7.43 per common share – diluted (2003 – $2,326 million; $4.91 per common share – basic; $4.85 per common share – diluted).

The fair value of each option granted is estimated on the date of grant using the Black-Scholes option-pricing model with weighted average assumptions for grants as follows:

| *For the years ended December 31* | 2003 | 2002 |
|---|---|---|
| Weighted Average Fair Value of Options Granted *(C$)* | $ 12.21 | $ 13.31 |
| Risk-Free Interest Rate | 3.87% | 4.29% |
| Expected Lives *(years)* | 3.00 | 3.00 |
| Expected Volatility | 0.33 | 0.35 |
| Annual Dividend per Share *(C$/common share)* | $ 0.40 | $ 0.40 |

## A) Pensions

The most recent actuarial evaluation completed for the Company is dated December 31, 2004.

The Company sponsors both defined benefit and defined contribution plans providing pension and other retirement and post-employment benefits ("OPEB") to substantially all of its employees.

| *For the years ended December 31* | 2004 | 2003 | 2002 |
|---|---|---|---|
| Total Expense for Defined Contribution Plans | $ 19 | $ 12 | $ 9 |

Information about defined benefit and post-retirement benefit plans, in aggregate, is as follows:

| | Pension Benefits | | OPEB | |
|---|---|---|---|---|
| *As at December 31* | 2004 | 2003 | 2004 | 2003 |
| Accrued Benefit Obligation, Beginning of Year | $ 214 | $ 159 | $ 14 | $ 8 |
| Beginning of year adjustment | (1) | – | – | – |
| Current service cost | 5 | 5 | 1 | 1 |
| Interest cost | 13 | 11 | 1 | 1 |
| Benefits paid | (10) | (11) | – | – |
| Actuarial loss | 8 | 12 | 1 | 1 |
| Contributions | 1 | 1 | – | – |
| Plan amendments | – | – | – | 1 |
| Foreign exchange | 16 | 37 | 2 | 2 |
| Accrued Benefit Obligation, End of Year | $ 246 | $ 214 | $ 19 | $ 14 |

| | Pension Benefits | | OPEB | |
|---|---|---|---|---|
| *As at December 31* | 2004 | 2003 | 2004 | 2003 |
| Fair Value of Plan Assets, Beginning of Year | $ 203 | $ 117 | $ – | $ – |
| Beginning of year adjustment | – | (1) | – | – |
| Actual return on plan assets | 19 | 16 | – | – |
| Employer contributions | 17 | 51 | – | – |
| Employees' contributions | 1 | 1 | – | – |
| Benefits paid | (10) | (10) | – | – |
| Foreign exchange | 17 | 29 | – | – |
| Fair Value of Plan Assets, End of Year | $ 247 | $ 203 | $ – | $ – |

| | Pension Benefits | | OPEB | |
|---|---|---|---|---|
| *As at December 31* | 2004 | 2003 | 2004 | 2003 |
| Funded Status – Plan Assets less than Benefit Obligation | $ 1 | $ (11) | $ (19) | $ (14) |
| Amounts Not Recognized: | | | | |
| Unamortized net actuarial loss | 54 | 64 | 4 | 2 |
| Unamortized past service cost | 10 | 12 | 2 | 1 |
| Net transitional asset | (11) | (12) | 2 | 3 |
| Accrued Benefit Asset | $ 54 | $ 53 | $ (11) | $ (8) |

| | Pension Benefits | | OPEB | |
|---|---|---|---|---|
| *As at December 31* | 2004 | 2003 | 2004 | 2003 |
| Prepaid Benefit Cost | $ 54 | $ 53 | $ – | $ – |
| Accrued Benefit Cost | – | – | (11) | (8) |
| Net Amount Recognized | $ 54 | $ 53 | $ (11) | $ (8) |

The Company's other post employment benefit plans are funded on an as required basis.

The weighted average assumptions used to determine benefit obligations are as follows:

| As at December 31 | Pension Benefits 2004 | Pension Benefits 2003 | OPEB 2004 | OPEB 2003 |
|---|---|---|---|---|
| Discount Rate | **5.75%** | 6.00% | **5.75%** | 6.00% |
| Rate of Compensation Increase | **4.60%** | 4.75% | **5.65%** | 5.75% |

The weighted average assumptions used to determine periodic expense are as follows:

| For the years ended December 31 | Pension Benefits 2004 | Pension Benefits 2003 | OPEB 2004 | OPEB 2003 |
|---|---|---|---|---|
| Discount Rate | **6.00%** | 6.50% | **6.00%** | 6.50% |
| Expected Long-Term Rate of Return on Plan Assets | | | | |
| Registered pension plans | **6.75%** | 6.75% | **n/a** | n/a |
| Supplemental pension plans | **3.375%** | 3.375% | **n/a** | n/a |
| Rate of Compensation Increase | **4.75%** | 4.75% | **5.75%** | 5.75% |

The periodic expense for benefits is as follows:

| For the years ended December 31 | Pension Benefits 2004 | Pension Benefits 2003 | Pension Benefits 2002 | OPEB 2004 | OPEB 2003 | OPEB 2002 |
|---|---|---|---|---|---|---|
| Current Service Cost | **$ 5** | $ 5 | $ 2 | **$ 1** | $ 1 | $ 1 |
| Interest Cost | **13** | 11 | 8 | **1** | 1 | – |
| Actual Return on Plan Assets | **(19)** | (16) | 9 | **–** | – | – |
| Actuarial Loss on Accrued Benefit Obligation | **8** | 12 | 9 | **1** | 1 | – |
| Plan Amendment | **–** | – | 9 | **–** | 2 | – |
| Difference Between Actual and: | | | | | | |
| Expected return on plan assets | **7** | 7 | (17) | **–** | – | – |
| Recognized actuarial loss | **(4)** | (8) | (8) | **(1)** | (1) | – |
| Difference Between Amortization of Past Service Costs and Actual Plan Amendments | **2** | 1 | (8) | **–** | (2) | – |
| Amortization of Transitional Obligation | **(2)** | (2) | (2) | **–** | – | – |
| Curtailment Loss | **–** | – | 1 | **–** | – | – |
| Special Termination Benefits | **–** | – | 2 | **–** | – | – |
| Expense for Defined Contribution Plan | **19** | 12 | 9 | **–** | – | – |
| Net Benefit Plan Expense | **$ 29** | $ 22 | $ 14 | **$ 2** | $ 2 | $ 1 |

The average remaining service period of the active employees covered by the defined benefit pension plan is eight years. The average remaining service period of the active employees covered by the other retirement benefits plan is 12 years.

After the business combination transaction as described in Note 3, a number of employees were involuntarily terminated. Terminated members of the defined benefit pension plan, who were age 50 or above, could elect enhanced benefits under the registered pension plan. For pension accounting purposes, this resulted in special termination benefits being provided and a curtailment event that impacted some of the pension arrangements sponsored by the Company.

Assumed health care cost trend rates are as follows:

| As at December 31 | 2004 | 2003 |
|---|---|---|
| Health Care Cost Trend Rate for Next Year | **10.00%** | 10.00% |
| Rate that the Trend Rate Gradually Trends To | **5.00%** | 5.00% |
| Year that the Trend Rate Reaches the Rate which it is Expected to Remain At | **2015** | 2014 |

Assumed health care cost trend rates have an effect on the amounts reported for the other benefit plans. A one percentage point change in assumed health care cost trend rates would have the following effects:

| | One Percentage Point Increase | One Percentage Point Decrease |
|---|---|---|
| Effect on Total of Service and Interest Cost | $ – | $ – |
| Effect on Post Retirement Benefit Obligation | $ 2 | $ (1) |

The Company's pension plan asset allocations are as follows:

| Asset Category | Target Allocation % Normal | Target Allocation % Range | % of Plan Assets at December 31 2004 | % of Plan Assets at December 31 2003 | Expected Long-Term Rate of Return |
|---|---|---|---|---|---|
| Domestic Equity | 35 | 25-45 | **38** | 35 | |
| Foreign Equity | 30 | 20-40 | **28** | 29 | |
| Bonds | 30 | 20-40 | **27** | 27 | |
| Real Estate and Other | 5 | 0-20 | **7** | 9 | |
| Total | 100 | | **100** | 100 | 6.75% |

The expected rate of return on plan assets is based on historical and projected rates of return for each asset class in the plan investment portfolio. The objective of the asset allocation policy is to manage the funded status of the plan at an appropriate level of risk, giving consideration to the security of the assets and the potential volatility of market returns and the resulting effect on both contribution requirements and pension expense. The long-term return is expected to achieve or exceed the return from a composite benchmark comprised of passive investments in appropriate market indices. The Supplemental Pension Plan (approximately $40 million) is funded through a retirement compensation arrangement and is subject to the applicable Canada Revenue Agency regulations.

The asset allocation structure is subject to diversification requirements and constraints which reduce risk by limiting exposure to individual equity investments, credit rating categories and foreign currency exposure.

The Company expects to contribute $6 million to the plans in 2005. Contributions by the participants to the pension and other benefits plans were $1 million for the year ended December 31, 2004 (2003 – $1 million; 2002 – nil).

Estimated future payments for pension and other benefits are as follows:

| | Pension Benefits | OPEB |
|---|---|---|
| 2005 | $ 12 | $ – |
| 2006 | 13 | 1 |
| 2007 | 13 | 1 |
| 2008 | 14 | 1 |
| 2009 | 15 | 1 |
| 2010 – 2014 | 88 | 7 |
| Total | $ 155 | $ 11 |

## B) Share Appreciation Rights

EnCana has in place a program whereby certain employees are granted Share Appreciation Rights ("SAR's") which entitle the employee to receive a cash payment equal to the excess of the market price of the Company's Common Shares at the time of exercise over the exercise price of the right. SAR's granted expire after five years.

The following tables summarize the information about the SAR's:

| *As at December 31* | 2004 Outstanding SAR's | 2004 Weighted Average Exercise Price | 2003 Outstanding SAR's | 2003 Weighted Average Exercise Price |
|---|---|---|---|---|
| **Canadian Dollar Denominated** *(C$)* | | | | |
| Outstanding, Beginning of Year | **1,175,070** | **35.87** | 2,284,901 | 35.56 |
| Exercised | **(698,775)** | **35.48** | (1,101,987) | 35.17 |
| Forfeited | **(11,040)** | **29.25** | (7,844) | 46.28 |
| Outstanding, End of Year | **465,255** | **36.61** | 1,175,070 | 35.87 |
| Exercisable, End of Year | **465,255** | **36.61** | 1,175,070 | 35.87 |
| **U.S. Dollar Denominated** *(US$)* | | | | |
| Outstanding, Beginning of Year | **753,417** | **28.98** | 1,346,437 | 28.52 |
| Exercised | **(365,647)** | **29.19** | (589,340) | 27.91 |
| Forfeited | **(1,840)** | **25.29** | (3,680) | 30.73 |
| Outstanding, End of Year | **385,930** | **28.80** | 753,417 | 28.98 |
| Exercisable, End of Year | **385,930** | **28.80** | 753,417 | 28.98 |

| As at December 31, 2004 | SAR's Outstanding | | |
|---|---|---|---|
| Range of Exercise Price | Number of SAR's | Weighted Average Remaining Contractual Life *(years)* | Weighted Average Exercise Price |
| **Canadian Dollar Denominated** *(C$)* | | | |
| 20.00 to 29.99 | 225,327 | 0.153 | 26.24 |
| 30.00 to 39.99 | – | – | – |
| 40.00 to 49.99 | 238,416 | 1.190 | 46.31 |
| 50.00 to 60.00 | 1,512 | 1.332 | 51.94 |
| | 465,255 | 0.689 | 36.61 |
| **U.S. Dollar Denominated** *(US$)* | | | |
| 20.00 to 29.99 | 166,640 | 1.379 | 26.69 |
| 30.00 to 40.00 | 219,290 | 1.158 | 30.39 |
| | 385,930 | 1.254 | 28.80 |

During the year, the Company recorded compensation costs of $17 million related to the outstanding SAR's (2003 – $12 million; 2002 – $4 million).

### C) Tandem Share Appreciation Rights

In 2004, all options to purchase common shares issued have an associated Tandem Share Appreciation Right ("TSAR") attached to them whereby the option holder has the right to receive cash payment equal to the excess of the market price of the Company's Common Shares at the time of exercise over the exercise price of the right. These TSAR's expire after five years.

The following tables summarize the information about the TSAR's:

| As at December 31 | 2004 | |
|---|---|---|
| | Outstanding TSAR's | Weighted Average Exercise Price |
| **Canadian Dollar Denominated** *(C$)* | | |
| Outstanding, Beginning of Year | – | – |
| Granted | 1,080,450 | 55.31 |
| Forfeited | (212,950) | 54.37 |
| Outstanding, End of Year | 867,500 | 55.54 |
| Exercisable, End of Year | – | – |

| As at December 31, 2004 | TSAR's Outstanding | | |
|---|---|---|---|
| Range of Exercise Price | Number of TSAR's | Weighted Average Remaining Contractual Life *(years)* | Weighted Average Exercise Price |
| **Canadian Dollar Denominated** *(C$)* | | | |
| 50.00 to 59.99 | 784,000 | 4.359 | 54.75 |
| 60.00 to 70.00 | 83,500 | 4.874 | 62.91 |
| | 867,500 | 4.408 | 55.54 |

During the year, the Company recorded compensation costs of $3 million related to the outstanding TSAR's.

### D) Deferred Share Units

The Company has in place a program whereby directors and certain key employees are issued Deferred Share Units ("DSU's"), which are equivalent in value to a common share of the Company. DSU's granted to directors vest immediately. DSU's granted to Senior Executives in 2002 vest over a three year period. DSU's expire on December 15th of the year following the employee's retirement or death.

The following table summarizes the information about the DSU's:

| *As at December 31* | 2004 | | 2003 | |
|---|---|---|---|---|
| | Outstanding DSU's | Average Share Price | Outstanding DSU's | Average Share Price |
| **Canadian Dollar Denominated** *(C$)* | | | | |
| Outstanding, Beginning of Year | 319,250 | 48.68 | 309,167 | 48.69 |
| Granted, Directors | 58,931 | 54.04 | 36,402 | 48.20 |
| Units, in lieu of dividends | 3,208 | 59.86 | 2,723 | 46.72 |
| Exercised | (6,083) | 48.68 | (29,042) | 48.04 |
| Outstanding, End of Year | 375,306 | 49.61 | 319,250 | 48.68 |
| Exercisable, End of Year | 293,955 | 52.55 | 80,645 | 48.68 |

During the year, the Company recorded compensation costs of $10 million related to the outstanding DSU's (2003 – $4 million; 2002 – $4 million).

### E) Performance Share Units

EnCana has in place a program whereby employees may be granted Performance Share Units ("PSU's") which entitle the employee to receive, upon vesting, either a common share of EnCana or a cash payment equal to the value of one common share of EnCana depending upon the terms of the PSU granted. PSU's vest at the end of a three year period. Their ultimate value will depend upon EnCana's performance measured over three calendar years. Performance will be measured by total shareholder return relative to a fixed North American oil and gas comparison group. If EnCana's performance is below the specified level compared to the comparison group, the units awarded will be forfeited. If EnCana's performance is at or above the specified level compared to the comparison group, the value of the PSU's shall be determined by EnCana's relative ranking, with payments ranging from one to two times for PSU's granted for the 2003 grant and one half to two times the PSU's granted for the 2004 grant.

PSU's granted in 2004 are to be paid in common shares (2003 – paid in cash).

The following table summarizes the information about the PSU's:

| *As at December 31* | 2004 | | 2003 | |
|---|---|---|---|---|
| | Outstanding PSU's | Average Share Price | Outstanding PSU's | Average Share Price |
| **Canadian Dollar Denominated** *(C$)* | | | | |
| Outstanding, Beginning of Year | 126,283 | 46.52 | – | – |
| Granted | 1,690,790 | 53.95 | 128,893 | 46.52 |
| Forfeited | (169,970) | 53.51 | (2,610) | 46.52 |
| Outstanding, End of Year | 1,647,103 | 53.42 | 126,283 | 46.52 |
| Exercisable, End of Year | – | – | – | – |
| **U.S. Dollar Denominated** *(US$)* | | | | |
| Outstanding, Beginning of Year | – | – | – | – |
| Granted | 250,224 | 41.12 | – | – |
| Forfeited | (25,609) | 41.12 | – | – |
| Outstanding, End of Year | 224,615 | 41.12 | – | – |
| Exercisable, End of Year | – | – | – | – |

During the year, the Company recorded compensation costs of $25 million related to the outstanding PSU's (2003 – $1 million; 2002 – nil).

## 17 FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

As a means of managing commodity price volatility, EnCana has entered into various financial instrument agreements and physical contracts. The following information presents all positions for financial instruments.

As discussed in Note 2, on January 1, 2004, the fair value of all outstanding financial instruments that were not considered accounting hedges was recorded in the Consolidated Balance Sheet with an offsetting net deferred loss amount. The deferred loss is recognized into net earnings over the life of the related contracts. Changes in fair value after that time are recorded in the Consolidated Balance Sheet with the associated unrealized gain or loss recorded in net earnings. The estimated fair value of all derivative instruments is based on quoted market prices or, in their absence, third party market indications and forecasts:

The following table presents a reconciliation of the change in the unrealized amounts during 2004:

| | Net Deferred Amounts Recognized on Transition | Fair Market Value | Total Unrealized Gain/(Loss) |
|---|---|---|---|
| Fair Value of Contracts, January 1, 2004 | $ 235 | $ (235) | $ – |
| Change in Fair Value of Contracts Still Outstanding at December 31, 2004 | – | 78 | 78 |
| Fair Value of Contracts Realized During 2004 | (307) | 307 | – |
| Fair Value of Contracts Entered into During 2004 | – | (339) | (339) |
| Fair Value of Contracts Outstanding | $ (72) | $ (189) | $ (261) |
| Premiums Paid on Collars and Options | | 110 | |
| Fair Value of Contracts Outstanding and Premiums Paid, End of Year | | $ (79) | |
| Amounts Allocated to Continuing Operations | $ (73) | $ (10) | $ (190) |
| Amounts Allocated to Discontinued Operations | 1 | (69) | (71) |
| | $ (72) | $ (79) | $ (261) |

The total realized loss recognized in net earnings from continuing operations for the year ended December 31, 2004 was $464 million ($686 million, before tax).

At December 31, 2004, the risk management amounts are recorded in the Consolidated Balance Sheet as follows:

| *As at December 31* | 2004 |
|---|---|
| Risk Management | |
| Current asset | $ 336 |
| Long-term asset | 87 |
| Current liability | 241 |
| Long-term liability | 192 |
| Net Risk Management Liability – Continuing Operations | (10) |
| Net Risk Management Liability – Discontinued Operations | (69) |
| | $ (79) |

A summary of all unrealized estimated fair value financial positions is as follows:

| *As at December 31* | Note | 2004 | 2003 |
|---|---|---|---|
| Commodity Price Risk | A | | |
| Natural gas | | $ 107 | $ (13) |
| Crude oil | | (143) | (174) |
| Power | | 2 | 4 |
| Foreign Currency Risk | B | – | 7 |
| Interest Rate Risk | C | 24 | 45 |
| Total Fair Value Positions – Continuing Operations | | (10) | (131) |
| Total Fair Value Positions – Discontinued Operations | | (69) | (104) |
| | | $ (79) | $ (235) |

## A) Commodity Price Risk

### NATURAL GAS

At December 31, 2004, the gas risk management activities from financial contracts had an unrealized gain of $36 million and a fair market value position of $107 million. The contracts were as follows:

| | Notional Volumes *(MMcf/d)* | Term | Average Price | | Fair Market Value |
|---|---|---|---|---|---|
| **Sales Contracts** | | | | | |
| Fixed Price Contracts | | | | | |
| NYMEX Fixed Price | 481 | 2005 | 6.72 | US$/Mcf | $ 81 |
| Colorado Interstate Gas (CIG) | 113 | 2005 | 4.87 | US$/Mcf | (27) |
| Other | 110 | 2005 | 5.21 | US$/Mcf | (23) |
| NYMEX Fixed Price | 525 | 2006 | 5.66 | US$/Mcf | (105) |
| Colorado Interstate Gas (CIG) | 100 | 2006 | 4.44 | US$/Mcf | (37) |
| Other | 171 | 2006 | 4.85 | US$/Mcf | (59) |
| Collars and Other Options | | | | | |
| Purchased NYMEX Put Options | 906 | 2005 | 5.46 | US$/Mcf | 29 |
| Other | 5 | 2005 | 4.57 – 7.23 | US$/Mcf | – |
| NYMEX 3-Way Call Spread | 180 | 2005 | 5.00/6.69/7.69 | US$/Mcf | (13) |
| Purchased NYMEX Put Options | 210 | 2006 | 5.00 | US$/Mcf | 5 |
| Basis Contracts | | | | | |
| Fixed NYMEX to AECO basis | 877 | 2005 | (0.66) | US$/Mcf | 70 |
| Fixed NYMEX to Rockies basis | 268 | 2005 | (0.49) | US$/Mcf | 19 |
| Other | 442 | 2005 | (0.47) | US$/Mcf | 4 |
| Fixed NYMEX to AECO basis | 703 | 2006 | (0.65) | US$/Mcf | 41 |
| Fixed NYMEX to Rockies basis | 312 | 2006 | (0.57) | US$/Mcf | 14 |
| Fixed NYMEX to CIG basis | 279 | 2006 | (0.83) | US$/Mcf | (9) |
| Other | 182 | 2006 | (0.36) | US$/Mcf | 2 |
| Fixed Rockies to CIG basis | 12 | 2007 | (0.10) | US$/Mcf | – |
| Fixed NYMEX to AECO basis | 345 | 2007-2008 | (0.65) | US$/Mcf | 17 |
| Fixed NYMEX to Rockies basis | 248 | 2007-2008 | (0.57) | US$/Mcf | 14 |
| Fixed NYMEX to CIG basis | 110 | 2007-2009 | (0.68) | US$/Mcf | 5 |
| **Purchase Contracts** | | | | | |
| Fixed Price Contract – Waha Purchase | 27 | 2005 | 5.90 | US$/Mcf | (2) |
| Fixed Price Contract – Waha Purchase | 23 | 2006 | 5.32 | US$/Mcf | 3 |
| | | | | | 29 |
| Gas Storage Optimization Financial Positions | | | | | 2 |
| Gas Marketing Financial Positions (1) | | | | | 5 |
| Total Unrealized Gain on Financial Contracts | | | | | 36 |
| Premiums Paid on Options | | | | | 71 |
| Total Fair Value Positions | | | | | $ 107 |

*(1) The gas marketing activities are part of the daily ongoing operations of the Company's proprietary production management.*

### CRUDE OIL

As at December 31, 2004, the Company's oil risk management activities from all financial contracts had an unrealized loss of $251 million and a fair market value position of $(212) million. The contracts were as follows:

| | Notional Volumes *(bbls/d)* | Term | Average Price | Fair Market Value |
|---|---|---|---|---|
| Fixed WTI NYMEX Price | 41,000 | 2005 | 28.41 | $ (209) |
| Costless 3-Way Put Spread | 9,000 | 2005 | 20.00/25.00/28.78 | (45) |
| Unwind WTI NYMEX Fixed Price | (4,500) | 2005 | 35.90 | 11 |
| Purchased WTI NYMEX Call Options | (38,000) | 2005 | 49.76 | 13 |
| Purchased WTI NYMEX Put Options | 35,000 | 2005 | 40.00 | 13 |
| Fixed WTI NYMEX Price | 15,000 | 2006 | 34.56 | (31) |
| Purchased WTI NYMEX Put Options | 22,000 | 2006 | 27.36 | (2) |
| | | | | (250) |
| Crude Oil Marketing Financial Positions *(1)* | | | | (1) |
| Total Unrealized Loss on Financial Contracts | | | | (251) |
| Premiums Paid on Options | | | | 39 |
| Total Fair Value Positions | | | | $ (212) |
| Total Fair Value Positions – Continuing Operations | | | | $ (143) |
| Total Fair Value Positions – Discontinued Operations | | | | (69) |
| | | | | $ (212) |

*(1) The crude oil marketing activities are part of the daily ongoing operations of the Company's proprietary production management.*

### POWER

EnCana has one electricity contract which expires in 2005. The contract was entered into as part of an electricity cost management strategy. At December 31, 2004, the unrealized gain on the contract was $2 million.

## B) Foreign Currency Risk

Foreign currency risk is the risk that a variation in exchange rates between the Canadian dollar and foreign currencies will affect the Company's operating and financial results. The Company has significant operations outside of Canada, which are subject to these foreign exchange risks.

No forward foreign currency exchange contracts were in place to hedge future commodity revenue streams as at December 31, 2004.

## C) Interest Rate Risk

The Company has entered into various derivative contracts to manage the Company's interest rate exposure on debt instruments. The impact of these transactions is described in Note 7.

The unrealized gains on the outstanding financial instruments as at December 31, 2004 were as follows:

| | Unrealized Gain |
|---|---|
| 5.80% Medium Term Notes | $ 11 |
| 7.50% Medium Term Notes | 5 |
| 8.75% Debenture | 8 |
| | $ 24 |

At December 31, 2004, the increase or decrease in net earnings for each one percent change in interest rates on floating rate debt amounts to $13 million (2003 – $14 million).

### D) Fair Value of Financial Assets and Liabilities

The fair values of financial instruments not recorded at their fair values that are included in the Consolidated Balance Sheet, other than long-term borrowings, approximate their carrying amount due to the short-term maturity of those instruments.

The estimated fair values of long-term borrowings have been determined based on market information where available, or by discounting future payments of interest and principal at estimated interest rates that would be available to the Company at year-end.

| *As at December 31* | 2004 | | 2003 | |
|---|---|---|---|---|
| | Carrying Amount | Fair Value | Carrying Amount | Fair Value |
| Financial Assets | | | | |
| Cash and cash equivalents | $ 602 | $ 602 | $ 113 | $ 113 |
| Accounts receivable | 1,898 | 1,898 | 1,165 | 1,165 |
| Financial Liabilities | | | | |
| Accounts payable, income taxes payable | $ 2,238 | $ 2,238 | $ 1,380 | $ 1,380 |
| Long-term debt | 7,930 | 8,479 | 6,375 | 6,767 |

### E) Credit Risk

A substantial portion of the Company's accounts receivable are with customers in the oil and gas industry and are subject to normal industry credit risks. The Board has approved a credit policy governing the Company's credit portfolio and procedures are in place to ensure adherence to this policy. With respect to counterparties to financial instruments, the Company partially mitigates associated credit risk by limiting transactions to counterparties with investment grade credit ratings.

All foreign currency agreements are with major financial institutions in Canada and the United States or with counterparties having investment grade credit ratings.

## 18 SUPPLEMENTARY INFORMATION

### A) Per Share Amounts

The following table summarizes the Common Shares used in calculating Net Earnings and Cash Flow per Common Share.

| *For the years ended December 31* | 2004 | 2003 | 2002 |
|---|---|---|---|
| Weighted Average Common Shares Outstanding – Basic | 460.4 | 474.1 | 417.8 |
| Effect of Stock Options and Other Dilutive Securities | 7.6 | 5.6 | 4.8 |
| Weighted Average Common Shares Outstanding – Diluted | 468.0 | 479.7 | 422.6 |

### B) Net Change in Non-Cash Working Capital from Continuing Operations

| *For the years ended December 31* | 2004 | 2003 | 2002 |
|---|---|---|---|
| **Operating Activities** | | | |
| Accounts receivable and accrued revenues | $ 665 | $ (107) | $ (276) |
| Inventories | 14 | (241) | (64) |
| Accounts payable and accrued liabilities | 601 | (252) | (14) |
| Income taxes payable | 175 | 32 | (535) |
| | $ 1,455 | $ (568) | $ (889) |
| **Investing Activities** | | | |
| Accounts payable and accrued liabilities | $ (21) | $ (113) | $ 195 |

### C) Supplementary Cash Flow Information – Continuing Operations

| *For the years ended December 31* | 2004 | 2003 | 2002 |
|---|---|---|---|
| Interest Paid | $ 401 | $ 284 | $ 261 |
| Income Taxes Paid (Received) | $ 148 | $ (127) | $ 567 |

## 19 COMMITMENTS AND CONTINGENCIES

### Commitments

| *As at December 31, 2004* | 2005 | 2006 | 2007 | 2008 | 2009 | Thereafter | Total |
|---|---|---|---|---|---|---|---|
| Pipeline Transportation | $ 297 | $ 262 | $ 237 | $ 220 | $ 182 | $ 1,010 | $ 2,208 |
| Purchases of Goods and Services | 121 | 23 | 14 | 9 | 3 | 5 | 175 |
| Product Purchases | 171 | 32 | 25 | 24 | 24 | 134 | 410 |
| Operating Leases | 42 | 43 | 41 | 36 | 29 | 152 | 343 |
| Capital Commitments | 190 | 41 | 22 | 4 | – | 38 | 295 |
| Total | $ 821 | $ 401 | $ 339 | $ 293 | $ 238 | $ 1,339 | $ 3,431 |
| Product Sales | $ 502 | $ 56 | $ 58 | $ 61 | $ 33 | $ 275 | $ 985 |

In addition to the above, the Company has made commitments related to its risk management program (see Note 17).

### Contingencies

#### LEGAL PROCEEDINGS

The Company is involved in various legal claims associated with the normal course of operations. The Company believes it has made adequate provision for such legal claims.

*Discontinued Merchant Energy Operations*

In July 2003, the Company's indirect wholly owned U.S. marketing subsidiary, WD Energy Services Inc. ("WD"), concluded a settlement with the U.S. Commodity Futures Trading Commission ("CFTC") of a previously disclosed CFTC investigation. The investigation related to alleged inaccurate reporting of natural gas trading information during 2000 and 2001 by former employees of WD's now discontinued Houston-based merchant energy trading operation to energy industry publications that compiled and reported index prices. All Houston-based merchant energy trading operations were discontinued following the merger with Alberta Energy Company Ltd. in 2002. Under the terms of the settlement, WD agreed to pay a civil monetary penalty in the amount of $20 million without admitting or denying the findings in the CFTC's order.

The Company and WD are defendants in a lawsuit filed by E. & J. Gallo Winery in the United States District Court in California and, along with other energy companies, are defendants in several other lawsuits in California (many of which are class actions) and three class action lawsuits filed in the United States District Court in New York. A motion by the Company and WD to dismiss the Gallo complaint on the basis that the Federal Energy Regulatory Commission had exclusive jurisdiction regarding this matter was not granted. The Gallo complaint claims damages in excess of $30 million, before potential trebling under California laws.

Most of the California class action lawsuits were transferred by the Judicial Panel on Multidistrict Litigation on a consolidated basis to the Nevada District Court and all of the New York lawsuits were consolidated in New York District Court by the plaintiff's application. The Nevada District Court has remanded the California State Court cases back to the California State Court for hearing. The California lawsuits relate to sales of natural gas in California from 1999 to the present and contain allegations that the defendants engaged in a conspiracy with unnamed competitors in the natural gas and derivatives market in California in violation of U.S. and California anti-trust and unfair competition laws to artificially raise the price of natural gas through various means including the illegal sharing of price information through online trading, price indices and wash trading. The New York lawsuits claim that the defendants' alleged manipulation of natural gas price indices resulted in higher prices of natural gas futures and option contracts traded on the NYMEX from 2000 to 2002. EnCana Corporation has been dismissed from the New York lawsuits, leaving only WD and several other companies unrelated to EnCana as the remaining defendants. As is customary, the class actions do not specify the amount of damages claimed.

The Company and WD intend to vigorously defend against these claims; however, the Company cannot predict the outcome of these proceedings or any future proceedings against the Company, whether these proceedings would lead to monetary damages which could have a material adverse effect on the Company's financial position, or whether there will be other proceedings arising out of these allegations.

### ASSET RETIREMENT

The Company is responsible for the retirement of long-lived assets related to its oil and gas properties and Midstream facilities at the end of their useful lives. The Company has recognized a liability of $611 million based on current legislation and estimated costs. Actual costs may differ from those estimated due to changes in legislation and changes in costs.

### INCOME TAX MATTERS

The operations of the Company are complex, and related tax interpretations, regulations and legislation in the various jurisdictions that the Company operates in are continually changing. As a result, there are usually some tax matters under review. The Company believes that the provision for taxes is adequate.

## 20 UNITED STATES ACCOUNTING PRINCIPLES AND REPORTING

The Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in Canada ("Canadian GAAP") which, in most respects, conform to accounting principles generally accepted in the United States ("U.S. GAAP"). The significant differences between Canadian and U.S. GAAP are described in this note.

### Reconciliation of Net Earnings Under Canadian GAAP to U.S. GAAP

| *For the years ended December 31* | Note | 2004 | 2003 | 2002 |
|---|---|---|---|---|
| Net Earnings – Canadian GAAP | | **$ 3,513** | $ 2,360 | $ 812 |
| Less: | | | | |
| Net Earnings From Discontinued Operations – Canadian GAAP | | **1,302** | 218 | 146 |
| Net Earnings From Continuing Operations – Canadian GAAP | | **2,211** | 2,142 | 666 |
| Increase (Decrease) under U.S. GAAP: | | | | |
| Revenues, net of royalties | B | **243** | (101) | (174) |
| Operating | B | **(3)** | – | – |
| Depreciation, depletion and amortization | A, G | **31** | 14 | (41) |
| Interest, net | B | **(41)** | 70 | 126 |
| Accretion of asset retirement obligation | G | **–** | – | 13 |
| Stock-based compensation | C | **(5)** | (1) | (3) |
| Income tax expense | E, G | **(73)** | 7 | 21 |
| Net Earnings From Continuing Operations – U.S. GAAP | | **2,363** | 2,131 | 608 |
| Net Earnings From Discontinued Operations – U.S. GAAP | | **1,370** | 152 | 146 |
| Net Earnings Before Change in Accounting Policy – U.S. GAAP | | **3,733** | 2,283 | 754 |
| Cumulative Effect of Change in Accounting Policy, net of tax | G | **–** | 66 | – |
| Net Earnings – U.S. GAAP | | **$ 3,733** | $ 2,349 | $ 754 |
| Net Earnings per Common Share Before Change in Accounting Policy – U.S. GAAP | | | | |
| Basic | | **$ 8.11** | $ 4.82 | $ 1.81 |
| Diluted | | **$ 7.98** | $ 4.76 | $ 1.78 |
| Net Earnings per Common Share Including Cumulative Effect of Change in Accounting Policy – U.S. GAAP | | | | |
| Basic | | **$ 8.11** | $ 4.95 | $ 1.81 |
| Diluted | | **$ 7.98** | $ 4.90 | $ 1.78 |

## Consolidated Statement of Earnings – U.S. GAAP

| *For the years ended December 31* | Note | 2004 | 2003 | 2002 |
|---|---|---|---|---|
| Revenues, Net of Royalties | B | $ 12,053 | $ 9,585 | $ 5,754 |
| Expenses | | | | |
| Production and mineral taxes | | 311 | 164 | 105 |
| Transportation and selling | | 499 | 484 | 332 |
| Operating | B | 1,353 | 1,196 | 749 |
| Purchased product | | 4,276 | 3,455 | 2,200 |
| Depreciation, depletion and amortization | A, G | 2,371 | 1,975 | 1,227 |
| Administrative | C | 197 | 173 | 121 |
| Interest, net | B | 438 | 213 | 160 |
| Accretion of asset retirement obligation | G | 22 | 17 | – |
| Foreign exchange gain | | (417) | (598) | (11) |
| Stock-based compensation | | 22 | 19 | – |
| Gain on dispositions | | (113) | (1) | (33) |
| Net Earnings Before Income Tax | | 3,094 | 2,488 | 904 |
| Income tax expense | E | 731 | 357 | 296 |
| Net Earnings From Continuing Operations – U.S. GAAP | | 2,363 | 2,131 | 608 |
| Net Earnings From Discontinued Operations – U.S. GAAP | A, B | 1,370 | 152 | 146 |
| Net Earnings Before Change in Accounting Policy – U.S. GAAP | | 3,733 | 2,283 | 754 |
| Cumulative Effect of Change in Accounting Policy, net of tax | G | – | 66 | – |
| Net Earnings – U.S. GAAP | | $ 3,733 | $ 2,349 | $ 754 |
| Net Earnings From Continuing Operations per Common Share – U.S. GAAP | | | | |
| Basic | | $ 5.13 | $ 4.49 | $ 1.46 |
| Diluted | | $ 5.05 | $ 4.44 | $ 1.44 |
| Net Earnings per Common Share Before Change in Accounting Policy – U.S. GAAP | | | | |
| Basic | | $ 8.11 | $ 4.82 | $ 1.81 |
| Diluted | | $ 7.98 | $ 4.76 | $ 1.78 |
| Net Earnings per Common Share Including Cumulative Effect of Change in Accounting Policy – U.S. GAAP | | | | |
| Basic | | $ 8.11 | $ 4.95 | $ 1.81 |
| Diluted | | $ 7.98 | $ 4.90 | $ 1.78 |

## Statement of Other Comprehensive Income

| *For the years ended December 31* | Note | 2004 | 2003 | 2002 |
|---|---|---|---|---|
| Net Earnings – U.S. GAAP | | $ 3,733 | $ 2,349 | $ 754 |
| Change in Fair Value of Financial Instruments | B, F | – | 4 | (7) |
| Foreign Currency Translation Adjustment | D | 420 | 1,046 | 136 |
| Other | | – | 6 | (6) |
| Other Comprehensive Income | | $ 4,153 | $ 3,405 | $ 877 |

## Condensed Consolidated Balance Sheet

*As at December 31*

| | Note | 2004 As reported | 2004 U.S. GAAP | 2003 As reported | 2003 U.S. GAAP |
|---|---|---|---|---|---|
| **Assets** | | | | | |
| Current Assets | A, B | $ 3,505 | $ 3,497 | $ 2,616 | $ 2,676 |
| Property, Plant and Equipment, net | A, G | 23,140 | 23,044 | 17,770 | 17,644 |
| Investments and Other Assets | B | 334 | 330 | 268 | 271 |
| Risk Management | B | 87 | 87 | – | 85 |
| Assets of Discontinued Operations | | 1,623 | 1,623 | 1,545 | 1,545 |
| Goodwill | | 2,524 | 2,524 | 1,911 | 1,911 |
| | | $ 31,213 | $ 31,105 | $ 24,110 | $ 24,132 |
| **Liabilities and Shareholders' Equity** | | | | | |
| Current Liabilities | A, B | $ 2,947 | $ 2,942 | $ 2,072 | $ 2,435 |
| Long-Term Debt | | 7,742 | 7,742 | 6,088 | 6,088 |
| Other Liabilities | B | 118 | 64 | 21 | 8 |
| Risk Management | B | 192 | 192 | – | 10 |
| Asset Retirement Obligation | G | 611 | 611 | 383 | 383 |
| Liabilities of Discontinued Operations | A, B | 102 | 102 | 112 | 82 |
| Future Income Taxes | E, G | 5,193 | 5,118 | 4,156 | 4,054 |
| | | 16,905 | 16,771 | 12,832 | 13,060 |
| Share Capital | C | 5,299 | 5,316 | 5,305 | 5,318 |
| Share Options, net | | 10 | 10 | 55 | 55 |
| Paid in Surplus | | 28 | 28 | 18 | 18 |
| Retained Earnings | | 7,935 | 7,955 | 5,276 | 5,076 |
| Foreign Currency Translation Adjustment | D | 1,036 | – | 624 | – |
| Accumulated Other Comprehensive Income | | – | 1,025 | – | 605 |
| | | 14,308 | 14,334 | 11,278 | 11,072 |
| | | $ 31,213 | $ 31,105 | $ 24,110 | $ 24,132 |

The following table summarizes the assets and liabilities of discontinued operations included in current assets and current liabilities:

*As at December 31*

| | Note | 2004 As reported | 2004 U.S. GAAP | 2003 As reported | 2003 U.S. GAAP |
|---|---|---|---|---|---|
| Assets of Discontinued Operations | A, B | $ 156 | $ 159 | $ 781 | $ 781 |
| Liabilities of Discontinued Operations | A, B | 280 | 315 | 405 | 500 |

## Condensed Consolidated Statement of Cash Flows – U.S. GAAP

*For the years ended December 31*

| | 2004 | 2003 | 2002 |
|---|---|---|---|
| **Operating Activities** | | | |
| Net earnings from continuing operations | $ 2,363 | $ 2,131 | $ 608 |
| Depreciation, depletion and amortization | 2,371 | 1,975 | 1,227 |
| Future income taxes | 164 | 470 | 362 |
| Unrealized (gain) loss on risk management | (15) | 31 | 48 |
| Unrealized foreign exchange gain | (285) | (545) | (23) |
| Accretion of asset retirement obligation | 22 | 17 | – |
| Gain on dispositions | (113) | (1) | – |
| Other | 98 | 57 | (163) |
| Cash flow from discontinued operations | 375 | 324 | 360 |
| Net change in other assets and liabilities | (176) | (84) | (17) |
| Net change in non-cash working capital from continuing operations | 1,455 | (568) | (889) |
| Net change in non-cash working capital from discontinued operations | (1,668) | 497 | 104 |
| **Cash From Operating Activities** | $ 4,591 | $ 4,304 | $ 1,617 |
| **Cash Used in Investing Activities** | $ (4,259) | $ (3,729) | $ (2,595) |
| **Cash From (Used in) Financing Activities** | $ 163 | $ (542) | $ 498 |

*Notes:*

*A) Full Cost Accounting*

The full cost method of accounting for crude oil and natural gas operations under Canadian and U.S. GAAP differ in the following respects. Under U.S. GAAP, a ceiling test is applied to ensure the unamortized capitalized costs in each cost centre do not exceed the sum of the present value, discounted at 10 percent, of the estimated unescalated future net operating revenue from proved reserves plus unimpaired unproved property costs less future development costs, related production costs and applicable taxes. Under Canadian GAAP, a similar ceiling test calculation is performed with the exception that cash flows from proved reserves are undiscounted and utilize forecast pricing to determine whether impairment exists. Any impairment amount is measured using the fair value of proved and probable reserves.

In computing its consolidated net earnings for U.S. GAAP purposes, the Company recorded additional depletion in 2001 and certain years prior to 2001 as a result of the application of the ceiling test. These charges were not required under the Canadian GAAP ceiling tests. As a result, the depletion base of unamortized capitalized costs is less for U.S. GAAP purposes.

Effective January 1, 2004, the Canadian Accounting Standard's Board amended the Full Cost Accounting Guideline. Under Canadian GAAP, depletion charges are calculated by reference to proved reserves estimated using estimated future prices and costs. Under U.S. GAAP, depletion charges are calculated by reference to proved reserves estimated using constant prices.

*B) Derivative Instruments and Hedging*

On January 1, 2004, the Company implemented under Canadian GAAP, EIC 128 "Accounting For Trading, Speculative or Non-Hedging Derivative Financial Instruments" which requires derivatives not designated as hedges to be recorded in the balance sheet as either assets or liabilities at their fair value. Changes in the derivative's fair value are recognized in current period earnings. Under the transitional rules any gain or loss at the implementation date is deferred and recognized into revenue once realized. Currently, Management has not designated any of the financial instruments as hedges.

The adoption of EIC 128 at January 1, 2004 resulted in the recognition of a $235 million deferred loss which will be recognized into earnings when realized. As at December 31, 2004, under Canadian GAAP a $72 million deferred gain remains, of which a $1 million deferred loss has been classified in liabilities of discontinued operations.

For U.S. GAAP, the Company adopted Statement of Financial Accounting Standards ("FAS") 133 effective January 1, 2001. FAS 133 requires that all derivatives be recorded in the balance sheet as either assets or liabilities at their fair value. Changes in the derivative's fair value are recognized in current period earnings unless specific hedge accounting criteria are met. Management has currently not designated any of the financial instruments as hedges for U.S. GAAP purposes under FAS 133.

Realized and unrealized gain/(loss) on derivatives related to:

| *For the years ended December 31* | 2004 | 2003 | 2002 |
|---|---|---|---|
| Commodity Prices (Revenues, net of royalties) | $ 76 | $ (205) | $ (174) |
| Interest and Currency Swaps (Interest, net) | (29) | 70 | 126 |
| Total Unrealized Gain (Loss) | $ 47 | $ (135) | $ (48) |
| Amounts Allocated to Continuing Operations | $ 15 | $ (31) | $ (48) |
| Amounts Allocated to Discontinued Operations | 32 | (104) | – |
| | $ 47 | $ (135) | $ (48) |

As at December 31, 2004, it is estimated that over the following 12 months, $3 million ($2 million, net of tax) will be reclassified into net earnings from other comprehensive income.

*C) Stock-based Compensation – CPL Reorganization*

Under Canadian GAAP, compensation costs have been recognized in the financial statements for stock options granted to employees and directors in 2003. For the effect of stock-based compensation on the Canadian GAAP financial statements, which would be the same adjustment under U.S. GAAP, see Note 15.

Under the Financial Accounting Standards Board ("FASB") Interpretation No. 44 "Accounting for Certain Transactions involving Stock Compensation", compensation expense must be recorded if the intrinsic value of the stock options is not exactly the same immediately before and after an equity restructuring. As part of the corporate reorganization of Canadian Pacific Ltd., an equity restructuring occurred which resulted in CPL stock options being replaced with stock options granted by EnCana as described in Note 15. This resulted in the replacement options having a different intrinsic value after the restructuring than prior to the restructuring. Canadian GAAP does not require revaluation of these options.

*D) Foreign Currency Translation Adjustments*

U.S. GAAP requires gains or losses arising from the translation of self-sustaining operations to be included in other comprehensive income. Canadian GAAP requires these amounts to be recorded in Shareholders' Equity.

*E) Future Income Taxes*

Under U.S. GAAP, enacted tax rates are used to calculate future taxes, whereas Canadian GAAP uses substantively enacted tax rates.

The future income tax adjustments included in the Reconciliation of Net Earnings under Canadian GAAP to U.S. GAAP and the Condensed Consolidated Balance Sheet include the effect of such rate differences, if any, as well as the tax effect of the other reconciling items noted.

The following table provides a reconciliation of the statutory rate to the actual tax rate:

| *For the years ended December 31* | 2004 | 2003 | 2002 |
|---|---|---|---|
| Using Canadian GAAP | | | |
| Net Earnings Before Income Tax | $ 2,869 | $ 2,506 | $ 983 |
| Canadian Statutory Rate | 39.1% | 41.0% | 42.3% |
| Expected Income Tax | 1,123 | 1,026 | 416 |
| Effect on Taxes Resulting from: | | | |
| Non-deductible Canadian crown payments | 192 | 231 | 147 |
| Canadian resource allowance | (246) | (258) | (200) |
| Canadian resource allowance on unrealized risk management losses | (10) | – | – |
| Statutory and other rate differences | (55) | (45) | (35) |
| Effect of tax rate reductions | (109) | (359) | (20) |
| Non-taxable capital gains | (91) | (119) | – |
| Previously unrecognized capital losses | 17 | (119) | – |
| Tax basis retained on dispositions | (179) | – | – |
| Large corporations tax | 24 | 27 | 23 |
| Other | (8) | (20) | (14) |
| | 658 | 364 | 317 |
| U.S. GAAP Adjustments to Net Earnings Before Income Tax | 225 | (18) | (79) |
| Expected Income Tax | 88 | (7) | (33) |
| Other | (15) | – | 12 |
| | 73 | (7) | (21) |
| Income Tax – U.S. GAAP | $ 731 | $ 357 | $ 296 |
| Effective Tax Rate | 23.6% | 14.3% | 32.7% |

The net future income tax liability is comprised of:

| *As at December 31* | 2004 | 2003 |
|---|---|---|
| Future Tax Liabilities | | |
| Property, plant and equipment in excess of tax values | $ 4,436 | $ 3,152 |
| Timing of partnership items | 1,005 | 1,162 |
| Future Tax Assets | | |
| Net operating losses carried forward | (103) | (99) |
| Other | (220) | (161) |
| Net Future Income Tax Liability | $ 5,118 | $ 4,054 |

*F) Other Comprehensive Income*

U.S. GAAP requires the disclosure, as other comprehensive income, of changes in equity during the period from transaction and other events from non-owner sources. Canadian GAAP does not require similar disclosure. Other comprehensive income arose from the transition adjustment resulting from the January 1, 2001 adoption of FAS 133. At December 31, 2004, accumulated other comprehensive income related to these items was a loss of $9 million, net of tax.

*G) Asset Retirement Obligation*

In 2003, the Company early adopted the Canadian accounting standard for asset retirement obligations, as outlined in the CICA handbook section 3110. This standard is equivalent to U.S. FAS 143 "Accounting for Asset Retirement Obligations", which was effective for fiscal periods beginning on or after January 1, 2003. Early adopting the Canadian standard eliminated a U.S. GAAP reconciling item in respect to accounting for the obligation, however a difference is created in how the transition amounts are disclosed.

U.S. GAAP requires the cumulative impact of a change in an accounting policy be presented in the current year Consolidated Statement of Earnings and prior periods not be restated. The following table illustrates the pro forma impact on the Company's financial results under U.S. GAAP if the prior periods had been restated:

| For the year ended December 31 | As Reported | Change | As Restated |
|---|---|---|---|
| 2002 Consolidated Statement of Earnings | | | |
| Net Earnings | $ 754 | $ 34 | $ 788 |
| Net Earnings per Common Share – Diluted | $ 1.78 | $ 0.08 | $ 1.86 |

*H) Consolidated Statement of Cash Flows*

Under U.S. GAAP, separate subtotals within cash flow from operating activities are not presented.

*I) Recent Accounting Pronouncements*

During 2004, the following new standards were issued:

*Share-Based Payment*

In 2004, FASB issued revised FAS 123 "Share-Based Payment". This amended statement eliminates the alternative to use Accounting Principles Board ("APB") Opinion No. 25's intrinsic value method of accounting, as was provided in the originally issued Statement 123. As a result, public entities are required to use the grant-date fair value of the award in measuring the cost of employee services received in exchange for an equity award of equity instruments. Compensation cost is required to be recognized over the requisite service period. For liability awards, entities are required to re-measure the fair value of the award at each reporting date up until the settlement date. Changes in fair value of liability awards during the requisite service period are required to be recognized as compensation cost over the vesting period. Compensation cost is not recognized for equity instruments for which employees do not render the requisite service. This amended statement is effective the beginning of the first interim or annual reporting period that begins after June 15, 2005. The Company is currently assessing the impact of this amendment.

*Exchange of Non-monetary Assets*

In 2004, FASB issued FAS 153 "Exchange of Non-monetary Assets". This statement is an amendment of APB Opinion No. 29 "Accounting for Non-monetary Transactions". Based on the guidance in APB Opinion No. 29, exchanges of non-monetary assets are to be measured based on the fair value of the assets exchanged. Furthermore, APB Opinion No. 29 previously allowed for certain exceptions to this fair value principle. FAS 153 eliminates APB Opinion No. 29's exception to fair value for non-monetary exchanges of similar productive assets and replaces this with a general exception for exchanges of non-monetary assets which do not have commercial substance. For purposes of this statement, a non-monetary exchange is defined as having commercial substance when the future cash flows of an entity are expected to change significantly as a result of the exchange. The provisions of this statement are effective for non-monetary asset exchanges which occur in fiscal periods beginning after June 15, 2005 and are to be applied prospectively. Earlier application is permitted for non-monetary asset exchanges which occur in fiscal periods beginning after the issue date of this statement. Currently, this statement does not have an impact on EnCana; however, this may result in a future impact to the Company if EnCana enters into any non-monetary asset exchanges.

The following unaudited disclosures on standardized measures of discounted cash flows and changes therein relating to proved oil and gas reserves are determined in accordance with United States Statement of Financial Accounting Standards No. 69 "Disclosures About Oil and Gas Producing Activities".

### Standardized Measure of Discounted Future Net Cash Flows and Changes Therein

In calculating the standardized measure of discounted future net cash flows, year-end constant prices and cost assumptions were applied to EnCana's annual future production from proved reserves to determine cash inflows. Future production and development costs are based on constant price assumptions and assume the continuation of existing economic, operating and regulatory conditions. Future income taxes are calculated by applying statutory income tax rates to future pre-tax cash flows after provision for the tax cost of the oil and natural gas properties based upon existing laws and regulations. The discount was computed by application of a 10 percent discount factor to the future net cash flows. The calculation of the standardized measure of discounted future net cash flows is based upon the discounted future net cash flows prepared by EnCana's independent qualified reserve evaluators in relation to the reserves they respectively evaluated, and adjusted by EnCana to account for management's estimates of risk management activities, asset retirement obligations and future income taxes.

EnCana cautions that the discounted future net cash flows relating to proved oil and gas reserves are an indication of neither the fair market value of EnCana's oil and gas properties, nor of the future net cash flows expected to be generated from such properties. The discounted future net cash flows do not include the fair market value of exploratory properties and probable or possible oil and gas reserves, nor is consideration given to the effect of anticipated future changes in crude oil and natural gas prices, development, asset retirement and production costs, and possible changes to tax and royalty regulations. The prescribed discount rate of 10 percent may not appropriately reflect future interest rates. The computation also excludes values attributable to EnCana's North Sea assets disposed of in 2004, Syncrude assets disposed of in 2003 and Midstream interests.

## DISCLOSURES ABOUT OIL AND GAS PRODUCING ACTIVITIES

### Net Proved Reserves (EnCana Share After Royalties) [1,2]

| | Natural Gas (billions of cubic feet) | | | | | Crude Oil and Natural Gas Liquids (millions of barrels) | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Canada | USA | United Kingdom | Other | Total | Canada | USA | Ecuador | United Kingdom | Other | Total |
| **2002** | | | | | | | | | | | |
| Beginning of year | 3,504 | 236 | 7 | – | **3,747** | 286.6 | 19.6 | – | 21.6 | – | **327.8** |
| Purchase of AEC reserves in place | 2,686 | 944 | – | – | **3,630** | 233.7 | 6.5 | 168.4 | – | – | **408.6** |
| Revisions and improved recovery | (1,140) | 731 | 7 | – | **(402)** | (15.5) | 4.6 | (33.5) | (9.1) | – | **(53.5)** |
| Extensions and discoveries | 726 | 319 | 10 | – | **1,055** | 96.9 | 3.3 | 31.1 | 89.2 | – | **220.5** |
| Purchase of reserves in place | 30 | 530 | – | – | **560** | 4.9 | 9.9 | – | – | – | **14.8** |
| Sale of reserves in place | (129) | (73) | – | – | **(202)** | (18.2) | (0.7) | – | – | – | **(18.9)** |
| Production | (604) | (114) | (4) | – | **(722)** | (46.5) | (2.3) | (10.2) | (4.1) | – | **(63.1)** |
| End of year | 5,073 | 2,573 | 20 | – | **7,666** | 541.9 | 40.9 | 155.8 | 97.6 | – | **836.2** |
| Developed | 4,139 | 1,446 | 9 | – | **5,594** | 299.2 | 21.9 | 104.6 | 8.3 | – | **434.0** |
| Undeveloped | 934 | 1,127 | 11 | – | **2,072** | 242.7 | 19.0 | 51.2 | 89.3 | – | **402.2** |
| Total | 5,073 | 2,573 | 20 | – | **7,666** | 541.9 | 40.9 | 155.8 | 97.6 | – | **836.2** |
| **2003** | | | | | | | | | | | |
| Beginning of year | 5,073 | 2,573 | 20 | – | **7,666** | 541.9 | 40.9 | 155.8 | 97.6 | – | **836.2** |
| Revisions and improved recovery | 73 | 1 | 3 | – | **77** | 32.3 | 0.5 | 0.4 | 23.5 | – | **56.7** |
| Extensions and discoveries | 867 | 706 | – | 90 | **1,663** | 110.9 | 7.4 | 11.9 | – | 0.9 | **131.1** |
| Purchase of reserves in place | 9 | 152 | 8 | – | **169** | 1.3 | 0.9 | 17.3 | 7.1 | – | **26.6** |
| Sale of reserves in place | (60) | (88) | – | (90) | **(238)** | (0.2) | (4.7) | (5.1) | – | (0.9) | **(10.9)** |
| Production | (706) | (215) | (5) | – | **(926)** | (56.8) | (3.4) | (18.6) | (3.7) | – | **(82.5)** |
| End of year | 5,256 | 3,129 | 26 | – | **8,411** | 629.4 | 41.6 | 161.7 | 124.5 | – | **957.2** |
| Developed | 3,984 | 1,833 | 13 | – | **5,830** | 306.1 | 26.3 | 115.0 | 16.7 | – | **464.1** |
| Undeveloped | 1,272 | 1,296 | 13 | – | **2,581** | 323.3 | 15.3 | 46.7 | 107.8 | – | **493.1** |
| Total | 5,256 | 3,129 | 26 | – | **8,411** | 629.4 | 41.6 | 161.7 | 124.5 | – | **957.2** |
| **2004** | | | | | | | | | | | |
| Beginning of year | 5,256 | 3,129 | 26 | – | **8,411** | 629.4 | 41.6 | 161.7 | 124.5 | – | **957.2** |
| Revisions and improved recovery | 67 | (252) | – | – | **(185)** | 31.1[3] | 0.2 | (11.5) | – | – | **19.8** |
| Extensions and discoveries | 1,422 | 1,009 | – | – | **2,431** | 93.6[3] | 47.6 | 21.2 | – | – | **162.4** |
| Purchase of reserves in place | 65 | 1,150 | 10 | – | **1,225** | 29.4 | 11.7 | – | 10.1 | – | **51.2** |
| Sale of reserves in place | (215) | (82) | (25) | – | **(322)** | (97.3) | (5.4) | – | (128.4) | – | **(231.1)** |
| Production | (771) | (318) | (11) | – | **(1,100)** | (56.6) | (4.7) | (28.1) | (6.2) | – | **(95.6)** |
| End of year before bitumen revisions | 5,824 | 4,636 | – | – | **10,460** | 629.6 | 91.0 | 143.3 | – | – | **863.9** |
| Revision due to bitumen price | – | – | – | – | **–** | (362.7)[4] | – | – | – | – | **(362.7)** |
| End of year | 5,824 | 4,636[5] | – | – | **10,460** | 266.9 | 91.0[5] | 143.3[6] | – | – | **501.2** |
| Developed | 4,406 | 2,496 | – | – | **6,902** | 210.2 | 31.5 | 122.5 | – | – | **364.2** |
| Undeveloped | 1,418 | 2,140 | – | – | **3,558** | 56.7 | 59.5 | 20.8 | – | – | **137.0** |
| Total | 5,824 | 4,636 | – | – | **10,460** | 266.9 | 91.0 | 143.3 | – | – | **501.2** |

*Notes:*

*(1) Definitions:*

*a. "Net" reserves are the remaining reserves of EnCana, after deduction of estimated royalties and including royalty interests.*

*b. "Proved" reserves are the estimated quantities of crude oil, natural gas and NGLs which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made.*

*c. "Proved Developed" reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.*

*d. "Proved Undeveloped" reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.*

*(2) EnCana does not file any estimates of total net proved crude oil or natural gas reserves with any U.S. federal authority or agency other than the SEC.*

*(3) An aggregate of approximately 75.8 million barrels of proved reserves in the Foster Creek area are subject to the revision due to bitumen price, including approximately 5.4 million barrels under revisions and improved recovery and approximately 70.4 million barrels under extensions and discoveries.*

*(4) Removal of EnCana's Foster Creek proved bitumen reserves due to year-end bitumen prices.*

*(5) Includes approximately 14 billion cubic feet of natural gas and approximately 38.8 million barrels of crude oil and NGLs reserves attributable to EnCana's Gulf of Mexico assets, which EnCana plans to dispose of in 2005.*

*(6) EnCana plans to dispose of its Ecuadorian operations in 2005. Accordingly, Ecuador is treated as a discontinued operation for financial reporting purposes.*

## DISCLOSURES ABOUT OIL AND GAS PRODUCING ACTIVITIES

### Standardized Measure of Discounted Future Net Cash Flows Related to Proved Oil and Gas Reserves

| | Canada | | | United States | | | Ecuador | | |
|---|---|---|---|---|---|---|---|---|---|
| *Years ended December 31 ($ millions)* | **2004** | 2003 | 2002 | **2004** | 2003 | 2002 | **2004** | 2003 | 2002 |
| Future cash inflows | **37,791** | 35,126 | 29,890 | **27,063** | 17,472 | 9,398 | **3,317** | 3,533 | 3,368 |
| Future production costs | **7,760** | 9,630 | 5,873 | **2,462** | 1,456 | 2,090 | **1,136** | 738 | 635 |
| Future development costs | **4,906** | 4,388 | 2,813 | **3,406** | 1,433 | 1,270 | **220** | 249 | 273 |
| Undiscounted pre-tax cash flows | **25,125** | 21,108 | 21,204 | **21,195** | 14,583 | 6,038 | **1,961** | 2,546 | 2,460 |
| Future income taxes | **6,279** | 5,874 | 6,353 | **7,021** | 4,960 | 1,504 | **342** | 536 | 585 |
| Future net cash flows | **18,846** | 15,234 | 14,851 | **14,174** | 9,623 | 4,534 | **1,619** | 2,010 | 1,875 |
| Less discount of net cash flows using a 10% rate | **6,668** | 5,219 | 6,018 | **6,686** | 4,735 | 2,383 | **417** | 643 | 617 |
| Discounted future net cash flows | **12,178** | 10,015 | 8,833 | **7,488** | 4,888 | 2,151 | **1,202** | 1,367 | 1,258 |

| | United Kingdom | | | Total | | |
|---|---|---|---|---|---|---|
| *Years ended December 31 ($ millions)* | **2004** | 2003 | 2002 | **2004** | 2003 | 2002 |
| Future cash inflows | – | 3,483 | 2,565 | **68,171** | 59,614 | 45,221 |
| Future production costs | – | 961 | 397 | **11,358** | 12,785 | 8,995 |
| Future development costs | – | 1,008 | 836 | **8,532** | 7,078 | 5,192 |
| Undiscounted pre-tax cash flows | – | 1,514 | 1,332 | **48,281** | 39,751 | 31,034 |
| Future income taxes | – | 456 | 483 | **13,642** | 11,826 | 8,925 |
| Future net cash flows | – | 1,058 | 849 | **34,639** | 27,925 | 22,109 |
| Less discount of net cash flows using a 10% rate | – | 493 | 438 | **13,771** | 11,090 | 9,456 |
| Discounted future net cash flows | – | 565 | 411 | **20,868** | 16,835 | 12,653 |

## DISCLOSURES ABOUT OIL AND GAS PRODUCING ACTIVITIES

### Changes in Standardized Measure of Future Net Cash Flows Relating to Proved Oil and Gas Reserves

| | Canada | | | United States | | | Ecuador | | |
|---|---|---|---|---|---|---|---|---|---|
| *Years ended December 31 ($ millions)* | **2004** | 2003 | 2002 | **2004** | 2003 | 2002 | **2004** | 2003 | 2002 |
| Balance, beginning of year | **10,015** | 8,833 | 3,060 | **4,888** | 2,151 | 300 | **1,367** | 1,258 | – |
| Changes resulting from: | | | | | | | | | |
| Sales of oil and gas produced during the period | **(3,965)** | (3,429) | (2,092) | **(1,474)** | (889) | (329) | **(264)** | (258) | (157) |
| Discoveries and extensions net of related costs | **3,562** | 1,272 | 1,293 | **2,436** | 1,381 | 293 | **236** | 126 | 330 |
| Purchases of proved AEC reserves in place | **–** | – | 6,810 | **–** | – | 1,044 | **–** | – | 1,830 |
| Purchases of proved reserves in place | **531** | 26 | 93 | **2,786** | 340 | 613 | **–** | 93 | – |
| Sales of proved reserves in place | **(1,579)** | (95) | (371) | **(271)** | (108) | (72) | **–** | (54) | – |
| Net change in prices and production costs | **2,264** | 242 | 3,358 | **143** | 2,751 | 194 | **(294)** | (47) | – |
| Revisions to quantity estimates | **546** | 416 | (1,345) | **(542)** | 4 | 667 | **(125)** | 4 | (354) |
| Accretion of discount | **1,349** | 1,636 | 455 | **725** | 304 | 56 | **176** | 182 | – |
| Previously estimated development costs incurred net of changes in future development costs | **57** | 340 | 101 | **22** | 534 | 54 | **15** | 89 | – |
| Other | **32** | 470 | (67) | **(49)** | 157 | (51) | **(29)** | (27) | – |
| Net change in income taxes | **(634)** | 304 | (2,462) | **(1,176)** | (1,737) | (618) | **120** | 1 | (391) |
| Balance, end of year | **12,178** | 10,015 | 8,833 | **7,488** | 4,888 | 2,151 | **1,202** | 1,367 | 1,258 |

| | United Kingdom | | | Total | | |
|---|---|---|---|---|---|---|
| *Years ended December 31 ($ millions)* | **2004** | 2003 | 2002 | **2004** | 2003 | 2002 |
| Balance, beginning of year | **565** | 411 | 140 | **16,835** | 12,653 | 3,500 |
| Changes resulting from: | | | | | | |
| Sales of oil and gas produced during the period | **(78)** | (83) | (81) | **(5,781)** | (4,659) | (2,659) |
| Discoveries and extensions net of related costs | **–** | – | 594 | **6,234** | 2,779 | 2,510 |
| Purchases of proved AEC reserves in place | **–** | – | – | **–** | – | 9,684 |
| Purchases of proved reserves in place | **77** | 57 | – | **3,394** | 516 | 706 |
| Sales of proved reserves in place | **(899)** | – | – | **(2,749)** | (257) | (443) |
| Net change in prices and production costs | **–** | (119) | (1) | **2,113** | 2,827 | 3,551 |
| Revisions to quantity estimates | **–** | 157 | (53) | **(121)** | 581 | (1,085) |
| Accretion of discount | **82** | 91 | 14 | **2,332** | 2,213 | 525 |
| Previously estimated development costs incurred net of changes in future development costs | **–** | 108 | 3 | **94** | 1,071 | 158 |
| Other | **–** | (38) | (8) | **(46)** | 562 | (126) |
| Net change in income taxes | **253** | (19) | (197) | **(1,437)** | (1,451) | (3,668) |
| Balance, end of year | **–** | 565 | 411 | **20,868** | 16,835 | 12,653 |

# RESULTS OF OPERATIONS AND CAPITALIZED COSTS *(unaudited)*

## DISCLOSURES ABOUT OIL AND GAS PRODUCING ACTIVITIES

### Results of Operations

| *Years ended December 31 ($ millions)* | Canada 2004 | Canada 2003 | Canada 2002 | United States 2004 | United States 2003 | United States 2002 | Ecuador 2004 | Ecuador 2003 | Ecuador 2002 |
|---|---|---|---|---|---|---|---|---|---|
| Oil and gas revenues, net of royalties, transportation and selling costs | **4,787** | 4,189 | 2,630 | **1,861** | 1,091 | 406 | **451** | 367 | 224 |
| Operating costs, production and mineral taxes, and accretion of asset retirement obligations | **822** | 760 | 538 | **387** | 202 | 77 | **187** | 109 | 67 |
| Depreciation, depletion and amortization | **1,752** | 1,511 | 871 | **487** | 297 | 206 | **263** | 159 | 79 |
| Operating income (loss) | **2,213** | 1,918 | 1,221 | **987** | 592 | 123 | **1** | 99 | 78 |
| Income taxes | **841** | 218 | 456 | **375** | 219 | 47 | **5** | 17 | 28 |
| Results of operations | **1,372** | 1,700 | 765 | **612** | 373 | 76 | **(4)** | 82 | 50 |

| *Years ended December 31 ($ millions)* | United Kingdom 2004 | United Kingdom 2003 | United Kingdom 2002 | Other 2004 | Other 2003 | Other 2002 | Total 2004 | Total 2003 | Total 2002 |
|---|---|---|---|---|---|---|---|---|---|
| Oil and gas revenues, net of royalties, transportation and selling costs | **117** | 102 | 92 | **–** | – | – | **7,216** | 5,749 | 3,352 |
| Operating costs, production and mineral taxes, and accretion of asset retirement obligations | **39** | 19 | 11 | **4** | 20 | 29 | **1,439** | 1,110 | 722 |
| Depreciation, depletion and amortization | **118** | 74 | 39 | **25** | 83 | 35 | **2,645** | 2,124 | 1,230 |
| Operating income (loss) | **(40)** | 9 | 42 | **(29)** | (103) | (64) | **3,132** | 2,515 | 1,400 |
| Income taxes | **(15)** | 17 | 17 | **–** | (4) | – | **1,206** | 467 | 548 |
| Results of operations | **(25)** | (8) | 25 | **(29)** | (99) | (64) | **1,926** | 2,048 | 852 |

### Capitalized Costs

| *Years ended December 31 ($ millions)* | Canada 2004 | Canada 2003 | Canada 2002 | United States 2004 | United States 2003 | United States 2002 | Ecuador 2004 | Ecuador 2003 | Ecuador 2002 |
|---|---|---|---|---|---|---|---|---|---|
| Proved oil and gas properties | **22,455** | 18,549 | 12,504 | **7,552** | 3,485 | 2,769 | **1,784** | 1,372 | 1,000 |
| Unproved oil and gas properties | **1,855** | 1,981 | 1,573 | **728** | 501 | 415 | **45** | 70 | 60 |
| Total capital cost | **24,310** | 20,530 | 14,077 | **8,280** | 3,986 | 3,184 | **1,829** | 1,442 | 1,060 |
| Accumulated DD&A | **9,770** | 7,498 | 4,770 | **1,046** | 516 | 262 | **534** | 188 | 73 |
| Net capitalized costs | **14,540** | 13,032 | 9,307 | **7,234** | 3,470 | 2,922 | **1,295** | 1,254 | 987 |

| *Years ended December 31 ($ millions)* | United Kingdom 2004 | United Kingdom 2003 | United Kingdom 2002 | Other 2004 | Other 2003 | Other 2002 | Total 2004 | Total 2003 | Total 2002 |
|---|---|---|---|---|---|---|---|---|---|
| Proved oil and gas properties | **–** | 675 | 445 | **–** | – | – | **31,791** | 24,081 | 16,718 |
| Unproved oil and gas properties | **–** | 77 | 3 | **425** | 317 | 226 | **3,053** | 2,946 | 2,277 |
| Total capital cost | **–** | 752 | 448 | **425** | 317 | 226 | **34,844** | 27,027 | 18,995 |
| Accumulated DD&A | **–** | 230 | 136 | **247** | 206 | 98 | **11,597** | 8,638 | 5,339 |
| Net capitalized costs | **–** | 522 | 312 | **178** | 111 | 128 | **23,247** | 18,389 | 13,656 |

## COSTS INCURRED *(unaudited)*

### DISCLOSURES ABOUT OIL AND GAS PRODUCING ACTIVITIES

#### Costs Incurred

| | Canada | | | United States | | | Ecuador | | |
|---|---|---|---|---|---|---|---|---|---|
| *Years ended December 31 ($ millions)* | **2004** | 2003 | 2002 | **2004** | 2003 | 2002 | **2004** | 2003 | 2002 |
| Acquisitions | | | | | | | | | |
| – AEC unproved reserves | **–** | – | 1,496 | **–** | – | 444 | **–** | – | 221 |
| – other unproved reserves | **42** | 47 | 12 | **954** | 21 | 202 | **–** | 80 | – |
| – AEC proved reserves | **–** | – | 3,540 | **–** | – | 1,024 | **–** | – | 686 |
| – other proved reserves | **204** | 207 | 78 | **2,051** | 115 | 457 | **–** | 59 | – |
| Total acquisitions | **246** | 254 | 5,126 | **3,005** | 136 | 2,127 | **–** | 139 | 907 |
| Exploration costs | **555** | 846 | 403 | **164** | 187 | 226 | **28** | 20 | 35 |
| Development costs | **2,669** | 2,131 | 902 | **1,103** | 651 | 282 | **213** | 111 | 133 |
| Total costs incurred | **3,470** | 3,231 | 6,431 | **4,272** | 974 | 2,635 | **241** | 270 | 1,075 |

| | United Kingdom | | | Other | | | Total | | |
|---|---|---|---|---|---|---|---|---|---|
| *Years ended December 31 ($ millions)* | **2004** | 2003 | 2002 | **2004** | 2003 | 2002 | **2004** | 2003 | 2002 |
| Acquisitions | | | | | | | | | |
| – AEC unproved reserves | **–** | – | – | **–** | – | – | **–** | – | 2,161 |
| – other unproved reserves | **–** | 16 | – | **–** | – | – | **996** | 164 | 214 |
| – AEC proved reserves | **–** | – | – | **–** | – | – | **–** | – | 5,250 |
| – other proved reserves | **130** | 95 | – | **–** | – | – | **2,385** | 476 | 535 |
| Total acquisitions | **130** | 111 | – | **–** | – | – | **3,381** | 640 | 8,160 |
| Exploration costs | **22** | 30 | 16 | **79** | 78 | 118 | **848** | 1,161 | 798 |
| Development costs | **364** | 96 | 66 | **–** | – | – | **4,349** | 2,989 | 1,383 |
| Total costs incurred | **516** | 237 | 82 | **79** | 78 | 118 | **8,578** | 4,790 | 10,341 |

## Financial Statistics

| *($ millions, except per share amounts)* | 2004 Year | 2004 Q4 | 2004 Q3 | 2004 Q2 | 2004 Q1 | 2003 Year | 2003 Q4 | 2003 Q3 | 2003 Q2 | 2003 Q1 |
|---|---|---|---|---|---|---|---|---|---|---|
| Cash Flow | **4,980** | 1,491 | 1,363 | 1,131 | 995 | 4,459 | 1,254 | 977 | 1,007 | 1,221 |
| Per share – Basic | **10.82** | 3.25 | 2.95 | 2.46 | 2.16 | 9.41 | 2.71 | 2.06 | 2.10 | 2.54 |
| – Diluted | **10.64** | 3.21 | 2.92 | 2.43 | 2.13 | 9.30 | 2.69 | 2.04 | 2.08 | 2.52 |
| Net Earnings | **3,513** | 2,580 | 393 | 250 | 290 | 2,360 | 426 | 290 | 807 | 837 |
| Per share – Basic | **7.63** | 5.62 | 0.85 | 0.54 | 0.63 | 4.98 | 0.92 | 0.61 | 1.68 | 1.74 |
| – Diluted | **7.51** | 5.55 | 0.84 | 0.54 | 0.62 | 4.92 | 0.91 | 0.61 | 1.67 | 1.73 |
| Operating Earnings (1) | **1,976** | 573 | 559 | 379 | 465 | 1,399 | 316 | 278 | 277 | 528 |
| Per share – Diluted | **4.22** | 1.23 | 1.20 | 0.81 | 1.00 | 2.92 | 0.68 | 0.58 | 0.57 | 1.09 |
| Cash Flow from Continuing Operations | **4,605** | 1,429 | 1,259 | 1,021 | 896 | 4,135 | 1,103 | 918 | 990 | 1,124 |
| Per share – Basic | **10.00** | 3.11 | 2.73 | 2.22 | 1.94 | 8.72 | 2.39 | 1.94 | 2.06 | 2.34 |
| – Diluted | **9.84** | 3.07 | 2.70 | 2.19 | 1.92 | 8.62 | 2.37 | 1.92 | 2.04 | 2.32 |
| Net Earnings from Continuing Operations | **2,211** | 1,188 | 432 | 265 | 326 | 2,142 | 447 | 266 | 801 | 628 |
| Per share – Basic | **4.80** | 2.59 | 0.94 | 0.58 | 0.71 | 4.52 | 0.97 | 0.56 | 1.67 | 1.31 |
| – Diluted | **4.72** | 2.56 | 0.93 | 0.57 | 0.70 | 4.47 | 0.96 | 0.56 | 1.65 | 1.30 |
| Operating Earnings – Continuing Operations (2) | **1,989** | 612 | 553 | 362 | 462 | 1,350 | 337 | 254 | 271 | 488 |
| Per share – Diluted | **4.25** | 1.32 | 1.19 | 0.78 | 0.99 | 2.82 | 0.72 | 0.53 | 0.56 | 1.01 |
| Foreign Exchange Rates *(US$ per C$1)* | | | | | | | | | | |
| Average | **0.768** | 0.820 | 0.765 | 0.736 | 0.759 | 0.716 | 0.760 | 0.725 | 0.715 | 0.662 |
| Period end | **0.831** | 0.831 | 0.791 | 0.746 | 0.763 | 0.774 | 0.774 | 0.741 | 0.738 | 0.681 |

*(1) Operating Earnings is a non-GAAP measure defined as Net Earnings excluding after-tax gain/loss on discontinuance, after-tax effect of unrealized mark-to-market accounting gains/losses on derivative instruments, after-tax gains/losses on translation of U.S. dollar denominated debt issued in Canada and the effect of the reduction in income tax rates.*

*(2) Operating Earnings – Continuing Operations is a non-GAAP measure defined as Net Earnings from Continuing Operations excluding after-tax effect of unrealized mark-to-market accounting gains/losses on derivative instruments, after-tax gains/losses on translation of U.S. dollar denominated debt issued in Canada and the effect of the reduction in income tax rates.*

| **Common Shares Information** | 2004 Year | 2004 Q4 | 2004 Q3 | 2004 Q2 | 2004 Q1 | 2003 Year | 2003 Q4 | 2003 Q3 | 2003 Q2 | 2003 Q1 |
|---|---|---|---|---|---|---|---|---|---|---|
| Common Shares Outstanding *(millions)* | | | | | | | | | | |
| Period end | **450.3** | 450.3 | 462.0 | 461.0 | 459.8 | 460.6 | 460.6 | 465.0 | 479.9 | 480.6 |
| Average – Basic | **460.4** | 458.8 | 461.7 | 460.3 | 460.9 | 474.1 | 462.3 | 473.4 | 480.6 | 479.9 |
| Average – Diluted | **468.0** | 464.9 | 466.2 | 465.5 | 467.1 | 479.7 | 465.9 | 477.9 | 484.4 | 484.3 |
| Price Range *($ per share)* | | | | | | | | | | |
| TSX – C$ | | | | | | | | | | |
| High | **70.02** | 70.02 | 60.60 | 59.73 | 59.27 | 53.55 | 52.25 | 52.79 | 53.55 | 50.00 |
| Low | **51.00** | 57.90 | 52.30 | 52.99 | 51.00 | 44.60 | 44.60 | 47.49 | 45.26 | 45.74 |
| Close | **68.40** | 68.40 | 58.35 | 57.62 | 56.69 | 51.00 | 51.00 | 48.90 | 51.70 | 47.75 |
| NYSE – US$ | | | | | | | | | | |
| High | **57.43** | 57.43 | 46.92 | 44.73 | 44.25 | 40.08 | 40.08 | 38.34 | 39.63 | 33.50 |
| Low | **38.05** | 46.10 | 39.95 | 38.05 | 38.36 | 29.91 | 33.46 | 34.00 | 30.45 | 29.91 |
| Close | **57.06** | 57.06 | 46.30 | 43.16 | 43.12 | 39.44 | 39.44 | 36.38 | 38.37 | 32.36 |
| Share Volume Traded *(millions)* | **528.0** | 163.3 | 114.7 | 121.2 | 128.8 | 476.4 | 141.1 | 117.9 | 107.2 | 110.2 |
| Share Value Traded *(US$ millions weekly average)* | **456.9** | 636.0 | 364.8 | 392.9 | 403.7 | 317.6 | 397.3 | 321.5 | 289.9 | 266.7 |

| **Financial Metrics** | |
|---|---|
| Debt to Capitalization | 33% |
| Debt to EBITDA | 1.4x |
| Return on Capital Employed | 20% |
| Return on Common Equity | 27% |

# NET CAPITAL INVESTMENT *(unaudited)*

## Financial Statistics *(continued)*

| **Net Capital Investment** *($ millions)* | 2004 | 2003 |
|---|---|---|
| Upstream | | |
| Canada | $ 3,015 | $ 2,937 |
| United States | 1,249 | 830 |
| International New Ventures Exploration | 79 | 78 |
| | 4,343 | 3,845 |
| Midstream & Market Optimization | 64 | 223 |
| Corporate | 46 | 57 |
| Core Capital from Continuing Operations | $ 4,453 | $ 4,125 |
| Acquisitions | | |
| Upstream | | |
| Property | | |
| Canada | $ 64 | $ 261 |
| United States | 300 | 138 |
| Corporate | | |
| Savannah | – | 91 |
| Petrovera | 253 | – |
| Tom Brown, Inc. (1) | 2,335 | – |
| Midstream & Market Optimization | | |
| Other | 34 | 53 |
| Corporate | – | 50 |
| Dispositions | | |
| Upstream | | |
| Property | | |
| Canada | (877) | (108) |
| United States | (266) | (178) |
| Other Countries | – | (15) |
| Corporate | | |
| Petrovera | (540) | – |
| Midstream & Market Optimization | | |
| Property | (1) | – |
| Corporate | | |
| Alberta Ethane Gathering System Joint Venture | (108) | – |
| Kingston CoGen Partnership | (25) | – |
| Net Acquisition and Disposition Activity from Continuing Operations | $ 1,169 | $ 292 |
| Proceeds of Disposition of United Kingdom | $ (2,144) | $ – |
| Discontinued Operations | 728 | (995) |
| Discontinued Operations | $ (1,416) | $ (995) |

*(1) Net cash consideration excluding debt acquired of $406 million.*

# Operating Statistics – Sales Volumes *(unaudited)*

## Operating Statistics – After Royalties

| Sales Volumes | 2004 | | | | | 2003 | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Year | Q4 | Q3 | Q2 | Q1 | Year | Q4 | Q3 | Q2 | Q1 |
| **Continuing Operations** | | | | | | | | | | |
| Produced Gas *(MMcf/d)* | | | | | | | | | | |
| Canada | | | | | | | | | | |
| Production | **2,105** | 2,106 | 2,138 | 2,177 | 2,000 | 1,935 | 2,008 | 1,914 | 1,899 | 1,922 |
| Inventory (injection)/ withdrawal | **(6)** | (26) | – | – | – | 30 | – | – | – | 120 |
| Canada Sales [1] | **2,099** | 2,080 | 2,138 | 2,177 | 2,000 | 1,965 | 2,008 | 1,914 | 1,899 | 2,042 |
| United States | **869** | 1,007 | 958 | 824 | 684 | 588 | 654 | 604 | 558 | 534 |
| Total Produced Gas | **2,968** | 3,087 | 3,096 | 3,001 | 2,684 | 2,553 | 2,662 | 2,518 | 2,457 | 2,576 |
| Oil and Natural Gas Liquids *(bbls/d)* | | | | | | | | | | |
| North America | | | | | | | | | | |
| Light and Medium Oil | **56,215** | 52,725 | 52,824 | 64,448 | 54,940 | 54,459 | 56,585 | 54,597 | 52,733 | 53,890 |
| Heavy Oil | **84,164** | 79,336 | 89,682 | 79,899 | 87,729 | 87,867 | 95,059 | 94,985 | 82,001 | 79,171 |
| Natural Gas Liquids [2] | | | | | | | | | | |
| Canada | **13,452** | 13,452 | 12,804 | 13,588 | 13,971 | 14,278 | 13,348 | 13,758 | 14,740 | 15,291 |
| United States | **12,586** | 13,957 | 14,363 | 12,752 | 9,237 | 9,291 | 9,479 | 9,530 | 10,194 | 7,943 |
| Total Oil and Natural Gas Liquids [3] | **166,417** | 159,470 | 169,673 | 170,687 | 165,877 | 165,895 | 174,471 | 172,870 | 159,668 | 156,295 |
| Total Continuing Operations *(MMcfe/d)* | **3,966** | 4,044 | 4,114 | 4,025 | 3,679 | 3,548 | 3,709 | 3,555 | 3,415 | 3,514 |
| Total Continuing Operations *(BOE/d)* | **661,084** | 673,970 | 685,673 | 670,854 | 613,210 | 591,395 | 618,138 | 592,537 | 569,168 | 585,628 |
| **Discontinued Operations** | | | | | | | | | | |
| Ecuador | | | | | | | | | | |
| Production [4] | **76,872** | 76,235 | 76,567 | 78,376 | 76,320 | 51,089 | 72,731 | 54,582 | 36,754 | 39,893 |
| Transferred to OCP Pipeline [5] | **–** | – | – | – | – | (3,213) | – | (4,919) | (2,039) | (5,941) |
| Over/(under) lifting | **1,121** | 1,641 | (1,721) | (73) | 4,662 | (1,355) | 4,621 | (9,856) | 2,506 | (2,679) |
| Ecuador Sales *(bbls/d)* | **77,993** | 77,876 | 74,846 | 78,303 | 80,982 | 46,521 | 77,352 | 39,807 | 37,221 | 31,273 |
| United Kingdom *(BOE/d)* | **20,973** | 13,927 | 20,222 | 26,728 | 22,755 | 12,295 | 18,400 | 6,979 | 11,019 | 12,777 |
| Syncrude *(bbls/d)* | **–** | – | – | – | – | 7,629 | – | 3,399 | 7,316 | 20,070 |
| Total Discontinued Operations *(MMcfe/d)* | **594** | 551 | 570 | 630 | 623 | 399 | 574 | 301 | 333 | 385 |
| Total Discontinued Operations *(BOE/d)* | **98,966** | 91,803 | 95,068 | 105,031 | 103,737 | 66,445 | 95,752 | 50,185 | 55,556 | 64,120 |
| Total *(MMcfe/d)* | **4,560** | 4,595 | 4,684 | 4,655 | 4,302 | 3,947 | 4,283 | 3,856 | 3,748 | 3,899 |
| Total *(BOE/d)* | **760,050** | 765,773 | 780,741 | 775,885 | 716,947 | 657,840 | 713,890 | 642,722 | 624,724 | 649,748 |

*(1) Net dispositions total approximately 42 MMcf/day for the full year 2004.*
*(2) Natural gas liquids include condensate volumes.*
*(3) Net dispositions total approximately 15,500 bbls/day for the full year 2004.*
*(4) 2004 includes approximately 31,000 bbls/day related to Block 15.*
*(5) Crude oil production in Ecuador transferred to the OCP Pipeline for use by OCP in asset commissioning.*

## OPERATING STATISTICS – NETBACKS, ROYALTY RATES *(unaudited)*

### Operating Statistics – After Royalties *(continued)*

CONTINUING OPERATIONS

| **Per-unit Results** *(excluding impact of realized financial hedging)* | 2004 Year | 2004 Q4 | 2004 Q3 | 2004 Q2 | 2004 Q1 | 2003 Year | 2003 Q4 | 2003 Q3 | 2003 Q2 | 2003 Q1 |
|---|---|---|---|---|---|---|---|---|---|---|
| Produced Gas – Canada *($/Mcf)* | | | | | | | | | | |
| Price | **5.34** | 5.86 | 5.10 | 5.20 | 5.21 | 4.87 | 4.41 | 4.61 | 4.92 | 5.53 |
| Production and mineral taxes | **0.08** | 0.10 | 0.09 | 0.07 | 0.08 | 0.07 | 0.10 | 0.08 | 0.08 | 0.02 |
| Transportation and selling | **0.39** | 0.39 | 0.37 | 0.35 | 0.44 | 0.38 | 0.44 | 0.40 | 0.35 | 0.33 |
| Operating | **0.52** | 0.55 | 0.50 | 0.49 | 0.56 | 0.48 | 0.45 | 0.50 | 0.47 | 0.48 |
| Netback | **4.35** | 4.82 | 4.14 | 4.29 | 4.13 | 3.94 | 3.42 | 3.63 | 4.02 | 4.70 |
| Produced Gas – United States *($/Mcf)* | | | | | | | | | | |
| Price | **5.79** | 6.53 | 5.36 | 5.72 | 5.39 | 4.88 | 4.71 | 4.82 | 4.74 | 5.32 |
| Production and mineral taxes | **0.65** | 0.69 | 0.57 | 0.80 | 0.51 | 0.47 | 0.42 | 0.46 | 0.46 | 0.57 |
| Transportation and selling | **0.31** | 0.27 | 0.26 | 0.34 | 0.39 | 0.40 | 0.51 | 0.39 | 0.36 | 0.32 |
| Operating | **0.37** | 0.41 | 0.36 | 0.37 | 0.33 | 0.28 | 0.29 | 0.33 | 0.31 | 0.20 |
| Netback | **4.46** | 5.16 | 4.17 | 4.21 | 4.16 | 3.73 | 3.49 | 3.64 | 3.61 | 4.23 |
| Produced Gas – Total North America *($/Mcf)* | | | | | | | | | | |
| Price | **5.47** | 6.08 | 5.18 | 5.34 | 5.26 | 4.87 | 4.49 | 4.66 | 4.88 | 5.49 |
| Production and mineral taxes | **0.25** | 0.29 | 0.24 | 0.27 | 0.19 | 0.16 | 0.18 | 0.17 | 0.17 | 0.14 |
| Transportation and selling | **0.36** | 0.35 | 0.33 | 0.35 | 0.43 | 0.39 | 0.46 | 0.40 | 0.35 | 0.33 |
| Operating | **0.48** | 0.50 | 0.46 | 0.46 | 0.50 | 0.43 | 0.41 | 0.46 | 0.43 | 0.42 |
| Netback | **4.38** | 4.94 | 4.15 | 4.26 | 4.14 | 3.89 | 3.44 | 3.63 | 3.93 | 4.60 |
| Natural Gas Liquids – Canada *($/bbl)* | | | | | | | | | | |
| Price | **31.43** | 36.73 | 33.46 | 28.48 | 27.27 | 24.26 | 25.13 | 23.52 | 21.02 | 27.31 |
| Production and mineral taxes | **–** | – | – | – | – | – | – | – | – | – |
| Transportation and selling | **0.41** | 0.47 | 0.45 | 0.35 | 0.35 | 0.17 | 0.13 | 0.58 | – | – |
| Netback | **31.02** | 36.26 | 33.01 | 28.13 | 26.92 | 24.09 | 25.00 | 22.94 | 21.02 | 27.31 |
| Natural Gas Liquids – United States *($/bbl)* | | | | | | | | | | |
| Price | **35.43** | 38.74 | 36.09 | 32.93 | 32.77 | 26.97 | 26.68 | 25.50 | 24.64 | 32.18 |
| Production and mineral taxes | **3.82** | 3.94 | 4.05 | 3.93 | 3.09 | 2.03 | 2.69 | 2.64 | 1.21 | 1.55 |
| Transportation and selling | **–** | – | – | – | – | – | – | – | – | – |
| Netback | **31.61** | 34.80 | 32.04 | 29.00 | 29.68 | 24.94 | 23.99 | 22.86 | 23.43 | 30.63 |
| Natural Gas Liquids – Total North America *($/bbl)* | | | | | | | | | | |
| Price | **33.36** | 37.75 | 34.85 | 30.63 | 29.46 | 25.33 | 25.77 | 24.33 | 22.50 | 28.98 |
| Production and mineral taxes | **1.84** | 2.00 | 2.14 | 1.90 | 1.23 | 0.80 | 1.12 | 1.08 | 0.50 | 0.53 |
| Transportation and selling | **0.21** | 0.23 | 0.21 | 0.18 | 0.21 | 0.10 | 0.08 | 0.35 | – | – |
| Netback | **31.31** | 35.52 | 32.50 | 28.55 | 28.02 | 24.43 | 24.57 | 22.90 | 22.00 | 28.45 |
| Crude Oil – Light and Medium – North America *($/bbl)* | | | | | | | | | | |
| Price | **34.67** | 39.57 | 37.40 | 32.43 | 29.92 | 26.61 | 25.53 | 24.31 | 27.43 | 29.34 |
| Production and mineral taxes | **0.96** | 1.38 | 0.85 | 0.79 | 0.86 | 0.29 | 0.73 | (1.35) | 0.71 | 1.08 |
| Transportation and selling | **1.01** | 1.04 | 1.08 | 0.76 | 1.19 | 1.42 | 1.33 | 0.71 | 1.73 | 1.95 |
| Operating | **5.85** | 6.41 | 6.49 | 4.84 | 5.87 | 6.00 | 6.28 | 5.93 | 6.07 | 5.68 |
| Netback | **26.85** | 30.74 | 28.98 | 26.04 | 22.00 | 18.90 | 17.19 | 19.02 | 18.92 | 20.63 |
| Crude Oil – Heavy – North America *($/bbl)* | | | | | | | | | | |
| Price | **23.41** | 21.37 | 28.01 | 22.35 | 21.48 | 19.61 | 18.43 | 17.93 | 20.07 | 22.62 |
| Production and mineral taxes | **0.04** | 0.04 | 0.05 | (0.01) | 0.06 | (0.03) | 0.09 | (0.49) | 0.34 | (0.02) |
| Transportation and selling | **1.09** | (0.57) | 1.63 | 1.50 | 1.69 | 1.24 | 1.54 | 0.58 | 1.37 | 1.56 |
| Operating | **5.32** | 6.27 | 4.79 | 4.82 | 5.44 | 5.67 | 4.95 | 5.93 | 6.18 | 5.70 |
| Netback | **16.96** | 15.63 | 21.54 | 16.04 | 14.29 | 12.73 | 11.85 | 11.91 | 12.18 | 15.38 |

## Operating Statistics – After Royalties *(continued)*

### CONTINUING OPERATIONS *(continued)*

| **Per-unit Results** *(excluding impact of realized financial hedging) (continued)* | 2004 | | | | | 2003 | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Year | Q4 | Q3 | Q2 | Q1 | Year | Q4 | Q3 | Q2 | Q1 |
| Crude Oil – Total North America *($/bbl)* | | | | | | | | | | |
| Price | **27.92** | 28.63 | 31.49 | 26.85 | 24.73 | 22.29 | 21.08 | 20.26 | 22.95 | 25.34 |
| Production and mineral taxes | **0.41** | 0.57 | 0.34 | 0.35 | 0.37 | 0.09 | 0.33 | (0.80) | 0.49 | 0.43 |
| Transportation and selling | **1.06** | 0.07 | 1.42 | 1.17 | 1.50 | 1.31 | 1.46 | 0.63 | 1.51 | 1.72 |
| Operating | **5.53** | 6.33 | 5.42 | 4.83 | 5.61 | 5.80 | 5.45 | 5.93 | 6.13 | 5.70 |
| Netback | **20.92** | 21.66 | 24.31 | 20.50 | 17.25 | 15.09 | 13.84 | 14.50 | 14.82 | 17.49 |
| Total Liquids – Canada *($/bbl)* | | | | | | | | | | |
| Price | **28.21** | 29.36 | 31.63 | 26.99 | 24.95 | 22.47 | 21.41 | 20.54 | 22.76 | 25.55 |
| Production and mineral taxes | **0.37** | 0.52 | 0.31 | 0.32 | 0.34 | 0.08 | 0.30 | (0.73) | 0.44 | 0.38 |
| Transportation and selling | **1.00** | 0.11 | 1.35 | 1.10 | 1.40 | 1.21 | 1.36 | 0.62 | 1.36 | 1.54 |
| Operating | **5.05** | 5.75 | 4.98 | 4.42 | 5.11 | 5.27 | 5.01 | 5.43 | 5.53 | 5.11 |
| Netback | **21.79** | 22.98 | 24.99 | 21.15 | 18.10 | 15.91 | 14.74 | 15.22 | 15.43 | 18.52 |
| Total Liquids – North America *($/bbl)* | | | | | | | | | | |
| Price | **28.77** | 30.20 | 32.03 | 27.43 | 25.39 | 22.72 | 21.69 | 20.81 | 22.88 | 25.88 |
| Production and mineral taxes | **0.63** | 0.82 | 0.63 | 0.59 | 0.49 | 0.19 | 0.43 | (0.55) | 0.49 | 0.44 |
| Transportation and selling | **0.93** | 0.10 | 1.23 | 1.02 | 1.32 | 1.14 | 1.28 | 0.59 | 1.28 | 1.46 |
| Operating | **4.67** | 5.24 | 4.55 | 4.09 | 4.82 | 4.97 | 4.74 | 5.13 | 5.18 | 4.85 |
| Netback | **22.54** | 24.04 | 25.62 | 21.73 | 18.76 | 16.42 | 15.24 | 15.64 | 15.93 | 19.13 |
| Total North America *($/Mcfe)* | | | | | | | | | | |
| Price | **5.30** | 5.83 | 5.22 | 5.15 | 4.98 | 4.57 | 4.24 | 4.31 | 4.58 | 5.17 |
| Production and mineral taxes | **0.21** | 0.25 | 0.21 | 0.22 | 0.16 | 0.13 | 0.15 | 0.10 | 0.14 | 0.12 |
| Transportation and selling | **0.31** | 0.27 | 0.30 | 0.30 | 0.37 | 0.33 | 0.39 | 0.31 | 0.31 | 0.31 |
| Operating | **0.55** | 0.59 | 0.53 | 0.52 | 0.58 | 0.54 | 0.52 | 0.58 | 0.55 | 0.53 |
| Netback | **4.23** | 4.72 | 4.18 | 4.11 | 3.87 | 3.57 | 3.18 | 3.32 | 3.58 | 4.21 |

**Impact of Upstream Realized Financial Hedging**

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Natural gas *($/Mcf)* | **(0.22)** | (0.37) | (0.15) | (0.25) | (0.08) | (0.10) | 0.16 | (0.06) | (0.25) | (0.25) |
| Liquids *($/bbl)* | **(7.08)** | (8.24) | (8.75) | (6.53) | (4.79) | (3.41) | (3.29) | (2.76) | (2.08) | (5.64) |
| Total *($/Mcfe)* | **(0.46)** | (0.61) | (0.48) | (0.47) | (0.27) | (0.23) | (0.04) | (0.18) | (0.28) | (0.44) |

**Average Royalty Rates** *(excluding impact of realized financial hedging)*

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Produced Gas | | | | | | | | | | |
| Canada | **12.5%** | 12.0% | 12.2% | 12.7% | 13.3% | 12.9% | 12.2% | 12.9% | 14.2% | 12.4% |
| United States | **19.6%** | 19.8% | 18.3% | 21.1% | 19.3% | 20.0% | 19.5% | 20.2% | 20.1% | 20.5% |
| Crude Oil | | | | | | | | | | |
| Canada and United States | **9.0%** | 8.7% | 8.8% | 11.6% | 9.4% | 10.3% | 9.7% | 9.0% | 10.7% | 11.8% |
| Natural Gas Liquids | | | | | | | | | | |
| Canada | **15.7%** | 16.5% | 18.5% | 13.1% | 14.8% | 17.5% | 14.7% | 16.6% | 18.0% | 20.2% |
| United States | **18.7%** | 21.4% | 13.6% | 20.7% | 19.2% | 17.6% | 17.5% | 17.0% | 17.3% | 18.5% |
| Total North America | **13.7%** | 13.8% | 13.2% | 14.1% | 13.7% | 13.8% | 13.2% | 13.4% | 14.5% | 13.9% |

## Operating Statistics – After Royalties *(continued)*

### DISCONTINUED OPERATIONS

| **Per-unit Results** *(excluding impact of realized financial hedging)* | 2004 | | | | | 2003 | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Year | Q4 | Q3 | Q2 | Q1 | Year | Q4 | Q3 | Q2 | Q1 |
| Crude Oil – Ecuador *($/bbl)* | | | | | | | | | | |
| Price | **28.68** | 29.97 | 33.47 | 27.78 | 23.82 | 24.21 | 23.57 | 22.13 | 22.31 | 30.86 |
| Production and mineral taxes | **2.13** | 2.73 | 2.62 | 1.84 | 1.37 | 1.47 | 1.06 | 0.45 | 1.11 | 4.27 |
| Transportation and selling | **2.12** | 1.57 | 2.36 | 1.92 | 2.63 | 2.56 | 2.81 | 2.36 | 2.41 | 2.35 |
| Operating | **4.39** | 5.02 | 4.35 | 4.14 | 4.04 | 4.84 | 4.62 | 4.33 | 5.63 | 5.09 |
| Netback | **20.04** | 20.65 | 24.14 | 19.88 | 15.78 | 15.34 | 15.08 | 14.99 | 13.16 | 19.15 |
| Crude Oil – United Kingdom *($/bbl)* | | | | | | | | | | |
| Price | **36.92** | 46.19 | 40.88 | 34.68 | 31.11 | 28.11 | 27.05 | 27.92 | 27.17 | 30.61 |
| Transportation and selling | **2.06** | 2.17 | 2.44 | 1.85 | 1.94 | 1.97 | 1.70 | 1.98 | 1.86 | 2.45 |
| Operating | **6.75** | 5.00 | 9.98 | 7.84 | 3.86 | 5.09 | 6.23 | 6.55 | 4.69 | 2.92 |
| Netback | **28.11** | 39.02 | 28.46 | 24.99 | 25.31 | 21.05 | 19.12 | 19.39 | 20.62 | 25.24 |

| **Impact of Upstream Realized Financial Hedging – Crude Oil** | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Ecuador *($/bbl)* | **(9.66)** | (14.60) | (10.31) | (7.13) | (6.69) | – | – | – | – | – |
| United Kingdom *($/bbl)* (1) | **(7.62)** | (6.34) | (11.75) | (7.01) | (5.72) | – | – | – | – | – |

| **Average Royalty Rates** *(excluding impact of realized financial hedging)* | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Crude Oil | | | | | | | | | | |
| Ecuador | **27.1%** | 27.8% | 26.5% | 26.5% | 27.4% | 25.6% | 25.4% | 25.7% | 24.9% | 26.9% |

*(1) Excludes hedges unwound as a result of the United Kingdom disposition.*

## DRILLING ACTIVITY

The following tables summarize EnCana's gross participation and net interest in wells drilled for the periods indicated:

### Exploration Wells Drilled

| | Gas | | Oil | | Dry & Abandoned | | Total Working Interest | | Royalty | Total | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Gross | Net | Gross | Net | Gross | Net | Gross | Net | Gross | Gross | Net |
| **Continuing Operations** | | | | | | | | | | | |
| **2004** | | | | | | | | | | | |
| Canada | 566 | 534 | 48 | 47 | 9 | 6 | 623 | 587 | 51 | 674 | 587 |
| United States | 19 | 16 | 2 | – | – | – | 21 | 16 | – | 21 | 16 |
| Other | – | – | 3 | 2 | 5 | 2 | 8 | 4 | – | 8 | 4 |
| Total | 585 | 550 | 53 | 49 | 14 | 8 | 652 | 607 | 51 | 703 | 607 |
| 2003 | | | | | | | | | | | |
| Canada | 532 | 511 | 51 | 31 | 35 | 28 | 618 | 570 | 153 | 771 | 570 |
| United States | 40 | 35 | 7 | 2 | 4 | 2 | 51 | 39 | – | 51 | 39 |
| Other | 1 | – | – | – | 3 | 1 | 4 | 1 | – | 4 | 1 |
| Total | 573 | 546 | 58 | 33 | 42 | 31 | 673 | 610 | 153 | 826 | 610 |
| 2002 | | | | | | | | | | | |
| Canada | 423 | 382 | 84 | 72 | 44 | 37 | 551 | 491 | 190 | 741 | 491 |
| United States | 12 | 12 | 2 | 1 | 3 | 1 | 17 | 14 | – | 17 | 14 |
| Other | – | – | – | – | 4 | 2 | 4 | 2 | – | 4 | 2 |
| Total | 435 | 394 | 86 | 73 | 51 | 40 | 572 | 507 | 190 | 762 | 507 |
| **Discontinued Operations** | | | | | | | | | | | |
| Ecuador – 2004 | – | – | 6 | 3 | – | – | 6 | 3 | – | 6 | 3 |
| Ecuador – 2003 | – | – | 3 | 2 | – | – | 3 | 2 | – | 3 | 2 |
| Ecuador – 2002 | – | – | 7 | 5 | – | – | 7 | 5 | – | 7 | 5 |
| United Kingdom – 2004 | – | – | 1 | – | 4 | 2 | 5 | 2 | – | 5 | 2 |
| United Kingdom – 2003 | – | – | 2 | 1 | 5 | 3 | 7 | 4 | – | 7 | 4 |
| United Kingdom – 2002 | – | – | 7 | 3 | 2 | 1 | 9 | 4 | – | 9 | 4 |

DRILLING ACTIVITY *(continued)*

## Development Wells Drilled

| | Gas | | Oil | | Dry & Abandoned | | Total Working Interest | | Royalty | Total | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Gross | Net | Gross | Net | Gross | Net | Gross | Net | Gross | Gross | Net |
| **Continuing Operations** | | | | | | | | | | | |
| 2004 | | | | | | | | | | | |
| Canada | 3,632 | 3,419 | 386 | 364 | 16 | 15 | 4,034 | 3,798 | 1,105 | 5,139 | 3,798 |
| United States | 600 | 515 | 1 | – | 3 | 3 | 604 | 518 | – | 604 | 518 |
| Total | 4,232 | 3,934 | 387 | 364 | 19 | 18 | 4,638 | 4,316 | 1,105 | 5,743 | 4,316 |
| 2003 | | | | | | | | | | | |
| Canada | 3,964 | 3,901 | 756 | 650 | 24 | 18 | 4,744 | 4,569 | 1,347 | 6,091 | 4,569 |
| United States | 426 | 401 | – | – | 1 | 1 | 427 | 402 | – | 427 | 402 |
| Total | 4,390 | 4,302 | 756 | 650 | 25 | 19 | 5,171 | 4,971 | 1,347 | 6,518 | 4,971 |
| 2002 | | | | | | | | | | | |
| Canada | 1,397 | 1,340 | 433 | 349 | 30 | 23 | 1,860 | 1,712 | 690 | 2,550 | 1,712 |
| United States | 287 | 250 | 3 | 3 | 1 | 1 | 291 | 254 | – | 291 | 254 |
| Total | 1,684 | 1,590 | 436 | 352 | 31 | 24 | 2,151 | 1,966 | 690 | 2,841 | 1,966 |
| **Discontinued Operations** | | | | | | | | | | | |
| Ecuador – 2004 | – | – | 43 | 25 | 1 | 1 | 44 | 26 | – | 44 | 26 |
| Ecuador – 2003 | – | – | 53 | 39 | 6 | 6 | 59 | 45 | – | 59 | 45 |
| Ecuador – 2002 | – | – | 44 | 37 | 5 | 4 | 49 | 41 | – | 49 | 41 |
| United Kingdom – 2004 | – | – | 3 | 1 | – | – | 3 | 1 | – | 3 | 1 |
| United Kingdom – 2003 | – | – | 3 | – | – | – | 3 | – | – | 3 | – |
| United Kingdom – 2002 | – | – | 2 | – | – | – | 2 | – | – | 2 | – |

## INTEREST IN MATERIAL PROPERTIES

The following table summarizes EnCana's developed, undeveloped and total land holdings as at December 31, 2004:

| (thousands of acres) | | Developed | | Undeveloped | | Total | |
|---|---|---|---|---|---|---|---|
| | | Gross | Net | Gross | Net | Gross | Net |
| **Canada** | | | | | | | |
| Alberta | – Fee | 4,319 | 4,319 | 2,835 | 2,835 | 7,154 | 7,154 |
| | – Crown | 3,709 | 2,989 | 6,643 | 5,578 | 10,352 | 8,567 |
| | – Freehold | 185 | 101 | 245 | 192 | 430 | 293 |
| | | 8,213 | 7,409 | 9,723 | 8,605 | 17,936 | 16,014 |
| British Columbia | – Crown | 697 | 579 | 4,174 | 3,601 | 4,871 | 4,180 |
| | – Freehold | – | – | 7 | 7 | 7 | 7 |
| | | 697 | 579 | 4,181 | 3,608 | 4,878 | 4,187 |
| Saskatchewan | – Fee | 57 | 57 | 461 | 461 | 518 | 518 |
| | – Crown | 115 | 96 | 1,064 | 1,049 | 1,179 | 1,145 |
| | – Freehold | 13 | 9 | 104 | 97 | 117 | 106 |
| | | 185 | 162 | 1,629 | 1,607 | 1,814 | 1,769 |
| Manitoba | – Fee | 3 | 3 | 265 | 265 | 268 | 268 |
| | – Freehold | – | – | 23 | 23 | 23 | 23 |
| | | 3 | 3 | 288 | 288 | 291 | 291 |
| Newfoundland & Labrador | – Crown | – | – | 4,027 | 2,514 | 4,027 | 2,514 |
| Nova Scotia | – Crown | – | – | 1,834 | 1,043 | 1,834 | 1,043 |
| Northwest Territories | – Crown | – | – | 633 | 234 | 633 | 234 |
| Nunavut | – Crown | – | – | 817 | 26 | 817 | 26 |
| Beaufort | – Crown | – | – | 126 | 4 | 126 | 4 |
| **Total Canada** | | 9,098 | 8,153 | 23,258 | 17,929 | 32,356 | 26,082 |

## INTEREST IN MATERIAL PROPERTIES *(continued)*

| *(thousands of acres)* | | Developed | | Undeveloped | | Total | |
|---|---|---|---|---|---|---|---|
| | | Gross | Net | Gross | Net | Gross | Net |
| **United States** | | | | | | | |
| Colorado | – Federal/State Lands | 208 | 180 | 821 | 745 | 1,029 | 925 |
| | – Freehold | 112 | 102 | 212 | 191 | 324 | 293 |
| | – Fee | 3 | 3 | 60 | 60 | 63 | 63 |
| | | 323 | 285 | 1,093 | 996 | 1,416 | 1,281 |
| Washington | – Federal/State Lands | – | – | 459 | 456 | 459 | 456 |
| | – Freehold | – | – | 199 | 199 | 199 | 199 |
| | – Federal Acquired Lease | – | – | 219 | 213 | 219 | 213 |
| | | – | – | 877 | 868 | 877 | 868 |
| Texas | – Federal/State Lands | 8 | 3 | 205 | 204 | 213 | 207 |
| | – Freehold | 161 | 97 | 431 | 395 | 592 | 492 |
| | | 169 | 100 | 636 | 599 | 805 | 699 |
| Wyoming | – Federal/State Lands | 148 | 73 | 729 | 490 | 877 | 563 |
| | – Freehold | 26 | 18 | 81 | 46 | 107 | 64 |
| | – Bureau of Indian Affairs | 11 | 10 | 5 | 4 | 16 | 14 |
| | | 185 | 101 | 815 | 540 | 1,000 | 641 |
| Gulf of Mexico | – Federal/State Lands | – | – | 1,371 | 557 | 1,371 | 557 |
| Alaska | – Federal/State Lands | – | – | 1,337 | 531 | 1,337 | 531 |
| Other | – Federal Lands | 11 | 10 | 374 | 236 | 385 | 246 |
| | – Freehold | 19 | 10 | 22 | 13 | 41 | 23 |
| | – Fee | 1 | 1 | – | – | 1 | 1 |
| | | 31 | 21 | 396 | 249 | 427 | 270 |
| **Total United States** | | 708 | 507 | 6,525 | 4,340 | 7,233 | 4,847 |
| Chad | | – | – | 108,536 | 54,268 | 108,536 | 54,268 |
| Oman | | – | – | 9,606 | 9,606 | 9,606 | 9,606 |
| Qatar | | – | – | 2,161 | 2,161 | 2,161 | 2,161 |
| Greenland | | – | – | 985 | 862 | 985 | 862 |
| Yemen | | – | – | 1,879 | 691 | 1,879 | 691 |
| Brazil | | – | – | 1,444 | 554 | 1,444 | 554 |
| Australia | | – | – | 960 | 320 | 960 | 320 |
| Bahrain | | – | – | 97 | 48 | 97 | 48 |
| Azerbaijan | | – | – | 346 | 17 | 346 | 17 |
| **Total International** | | – | – | 126,014 | 68,527 | 126,014 | 68,527 |
| **Total** | | 9,806 | 8,660 | 155,797 | 90,796 | 165,603 | 99,456 |
| **Discontinued Operations** | | | | | | | |
| Ecuador | | 160 | 99 | 1,243 | 795 | 1,403 | 894 |

*Notes:*

*(1) This table excludes approximately 4.3 million gross acres under lease or sublease, reserving to EnCana royalties or other interests.*

*(2) Fee lands are those lands in which EnCana has a fee simple interest in the minerals rights and has either: (i) not leased out all of the mineral zones; or (ii) retained a working interest. In prior years, fee lands in which any zones were leased out were excluded as fee lands except with respect to lands in which EnCana retained a working interest. The current fee lands acreage summary now includes all fee titles owned by EnCana that have one or more zones that remained unleased or available for development.*

*(3) Crown/Federal/State lands are those owned by the federal, provincial, or state government or the First Nations, in which EnCana has purchased a working interest lease.*

*(4) Freehold lands are owned by individuals (other than a Government or EnCana), in which EnCana holds a working interest lease.*

*(5) Gross acres are the total area of properties in which EnCana has an interest.*

*(6) Net acres are the sum of EnCana's fractional interest in gross acres.*

# Corporate Information

## Corporate Officers

**Gwyn Morgan**
President & Chief Executive Officer

**Randall K. Eresman**
Executive Vice-President &
Chief Operating Officer

**Roger J. Biemans**
*Executive Vice-President*
*President, USA Region*

**Michael M. Graham**
*Executive Vice-President*
*President, Canadian Foothills & Frontier Region*

**Jeff E. Wojahn**
*Executive Vice-President*
*President, Canadian Plains Region*

**Brian C. Ferguson**
Executive Vice-President,
Corporate Development

**Kerry D. Dyte**
General Counsel &
Corporate Secretary

**R. William Oliver**
Executive Vice-President
*President, Midstream & Marketing Division*

**Gerard J. Protti**
Executive Vice-President,
Corporate Relations

**Drude Rimell**
Executive Vice-President,
Corporate Services

**John D. Watson**
Executive Vice-President &
Chief Financial Officer

**Thomas G. Hinton**
Treasurer

**William A. Stevenson**
Comptroller

## Board of Directors

**Michael N. Chernoff** [2, 6]
West Vancouver, British Columbia

**Ralph S. Cunningham** [2, 3]
Houston, Texas

**Patrick D. Daniel** [1, 5]
Calgary, Alberta

**Ian W. Delaney** [3, 4]
Toronto, Ontario

**William R. Fatt** [1]
Toronto, Ontario

**Michael A. Grandin** [3, 5, 6]
Calgary, Alberta

**Barry W. Harrison** [1, 4]
Calgary, Alberta

**Richard F. Haskayne, O.C.** [3, 4]
Calgary, Alberta

**Dale A. Lucas** [1, 5]
Calgary, Alberta

**Ken F. McCready** [2, 5]
Calgary, Alberta

**Gwyn Morgan**
Calgary, Alberta

**Valerie A.A. Nielsen** [2, 6]
Calgary, Alberta

**David P. O'Brien** [7]
Calgary, Alberta

**Jane L. Peverett** [1]
West Vancouver, British Columbia

**Dennis A. Sharp** [2, 4]
Calgary, Alberta/Montreal, Quebec

**James M. Stanford, O.C.** [1, 3, 6]
Calgary, Alberta

1 *Audit Committee*
2 *Corporate Responsibility, Environment, Health and Safety Committee*
3 *Human Resources and Compensation Committee*
4 *Nominating and Corporate Governance Committee*
5 *Pension Committee*
6 *Reserves Committee*
7 *Chairman of the Board, Chairman of Nominating and Corporate Governance Committee, and ex officio member of all other Board Committees.*

## EnCana Head Office

1800, 855 – 2nd Street S.W.
P.O. Box 2850
Calgary, Alberta, Canada T2P 2S5
Phone: 403-645-2000
Web site: www.encana.com

# CORPORATE INFORMATION

## TRANSFER AGENTS & REGISTRAR

Common Shares
**CIBC Mellon Trust Company**
Calgary, Montreal, Toronto, and
**Mellon Investor Services LLC**
New York

Shareholders are encouraged to contact CIBC Mellon Trust Company for information regarding their security holdings. They can be reached via the Answerline 416-643-5500 or toll-free throughout North America at 1-800-387-0825, or via facsimile at 416-643-5501.

Mailing Address
**CIBC Mellon Trust Company**
P.O. Box 7010
Adelaide Street Postal Station
Toronto, Ontario, Canada M5C 2W9

*Internet Addresses*
inquiries@cibcmellon.com (Email)
www.cibcmellon.com (Web site)

## TRUSTEE & REGISTRARS

**CIBC Mellon Trust Company**
*Canadian Medium Term Notes*
*8.75% Debentures*
Calgary, Toronto

**The Bank of New York**
*4.600% Senior Notes*
*4.750% Senior Notes*
*6.500% Senior Notes*
*7.375% Senior Notes*
*7.650% Senior Notes*
*8.125% Senior Notes*
New York

**The Bank of Nova Scotia Trust Company of New York**
*6.30% Senior Notes*
*7.20% Senior Notes*
New York

**Deutsche Bank Trust Company Americas**
*5.80% Senior Notes*
*(EnCana Holdings Finance Corp.)*
New York

## AUDITORS

**PricewaterhouseCoopers LLP**
Chartered Accountants
Calgary, Alberta

## INDEPENDENT QUALIFIED RESERVE EVALUATORS

*North America*

**DeGolyer and MacNaughton**
Dallas, Texas

**Gilbert Laustsen Jung Associates Ltd.**
Calgary, Alberta

**McDaniel & Associates Consultants Ltd.**
Calgary, Alberta

**Netherland, Sewell & Associates, Inc.**
Dallas, Texas

*International*

**Gilbert Laustsen Jung Associates Ltd.**
Calgary, Alberta

## STOCK EXCHANGES

*Common Shares (ECA)*
**Toronto Stock Exchange**
**New York Stock Exchange**

## PRINCIPAL SUBSIDIARIES & PARTNERSHIPS (1)

| | Percent Owned (2) |
|---|---|
| Alenco Inc. | 100 |
| EnCana Marketing (USA) Inc. | 100 |
| EnCana Oil & Gas (USA) Inc. | 100 |
| EnCana West Ltd. | 100 |
| 3080763 Nova Scotia Company | 100 |
| EnCana Midstream & Marketing | 100 |
| EnCana Oil & Gas Partnership | 100 |
| EnCana USA Holdings | 100 |

*(1) Entities whose total assets exceed 10 percent of total consolidated assets of EnCana Corporation or whose revenues exceed 10 percent of the total consolidated revenues of the Corporation for the year ended December 31, 2004.*
*(2) Includes indirect ownership.*

*The above is not a complete list of all of the subsidiaries and partnerships of EnCana Corporation.*

# INVESTOR INFORMATION

**Annual Meeting**
Shareholders of EnCana Corporation are invited to attend the Annual and Special Meeting being held on Wednesday, April 27, 2005 at 10:30 a.m., local time, at the Hyatt Regency Calgary, 700 Centre Street S.E., Calgary, Alberta. Those unable to do so are asked to sign and return the form of proxy that has been mailed to them.

**Annual Information Form (Form 40-F)**
EnCana's Annual Information Form (AIF) is filed with the securities regulators in Canada and the United States. Under the Multi-Jurisdictional Disclosure System, EnCana's AIF is filed as Form 40-F with the U.S. Securities and Exchange Commission.

**Shareholder Account Matters**
To change your address, transfer shares, eliminate duplicate mailings, have dividends deposited directly into accounts at financial institutions in Canada that provide electronic fund-transfer services, etc., please contact CIBC Mellon Trust Company.

**EnCana Web site**
EnCana's Web site contains a variety of corporate and investor information including, among other information, the following:

- Current stock prices
- Annual and Interim Reports
- Information Circular
- News releases
- Investor presentations
- Dividend information
- Shareholder support information

Web site: www.encana.com

Additional information, including copies of the 2004 EnCana Corporation Annual Report, may be obtained from:

**EnCana Corporation**
Investor Relations,
Corporate Development
1800, 855 – 2nd Street S.W.
P.O. Box 2850
Calgary, Alberta, Canada T2P 2S5
Phone: (403) 645-3550
Visit our Web site: www.encana.com

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**Sheila McIntosh**
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sheila.mcintosh@encana.com

**Paul Gagne**
Manager, Investor Relations
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Financial and business media inquiries should be directed to:

**Alan Boras**
Manager, Media Relations
(403) 645-4747
alan.boras@encana.com

General media inquiries should be directed to:

**Florence Murphy**
Vice-President, Public & Community Relations
(403) 645-4748
florence.murphy@encana.com

**Abbreviations**

| | |
|---|---|
| bbls | barrels |
| Bcf | billion cubic feet |
| Bcfe | billion cubic feet equivalent |
| BOE | barrel of oil equivalent |
| Btu | British thermal unit |
| CAPP | Canadian Association of Petroleum Producers |
| CO2E | carbon dioxide equivalent |
| GJ | gigajoule |
| km | kilometre(s) |
| kW | kilowatt |
| kWh | kilowatt hour |
| m | metre(s) |
| $m^3$OE | cubic metres oil equivalent |
| Mbbls | thousand barrels |
| MBOE | thousand barrels of oil equivalent |
| Mcf | thousand cubic feet |
| Mcfe | thousand cubic feet equivalent |
| MM | million |
| MMbbls | million barrels |
| MMBOE | million barrels of oil equivalent |
| MMBtu | million British thermal units |
| MMcf | million cubic feet |
| MMcfe | million cubic feet equivalent |
| MT | megatonnes |
| NGLs | natural gas liquids |
| PCI | product carbon intensity |
| Tcf | trillion cubic feet |
| Tcfe | trillion cubic feet equivalent |

ENCANA CORPORATION

Investor relations inquiries should be directed to:

Sheila McIntosh
Vice-President,
Investor Relations
(403) 645-2194

Paul Gagne
Manager,
Investor Relations
(403) 645-4737

Financial and business media inquiries should be directed to:

Alan Boras
Manager, Media Relations
(403) 645-4747

General media inquiries should be directed to:

Florence Murphy
Vice-President,
Public & Community Relations
(403) 645-4748

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